



**Energy
Conversion**
1976 – 2006

A History of Geothermal Energy
Research and Development
in the United States



Cover Photo Credits

The Geysers Geothermal Power Plant, Sonoma County, California
(Courtesy: Calpine Corporation)

This history of the U.S. Department of Energy's research program in geothermal energy is dedicated to the many government employees who worked diligently for the program's success. Those men and women are too numerous to mention individually, given the history's 30-year time span. But they deserve recognition nonetheless for their professionalism and exceptional drive to make geothermal technology a viable option in solving the Nation's energy problems. Special recognition is given here to those persons who assumed the leadership role for the program and all the duties and responsibilities pertaining thereto:

- Eric Willis, 1976-77
- James Bresee, 1977-78
- Bennie Di Bona, 1979-80
- John Salisbury, 1980-81
- John "Ted" Mock, 1982-94
- Allan Jelacic, 1995-1999
- Peter Goldman, 1999-2003
- Leland "Roy" Mink, 2003-06

These leaders, along with their able staffs, are commended for a job well done. The future of geothermal energy in the United States is brighter today than ever before thanks to their tireless efforts.

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Preface

In the 1970s, the publicly available information about geothermal systems was woefully inadequate. The understanding of geothermal resources and the means for their optimum development was primitive. Much of the extant information was held in private company files. Lack of information meant only a few companies invested in exploration and resource development. Utilities did not understand the geothermal resource, especially the risks and costs of development, and they were therefore reluctant to sign long-term geothermal power purchase agreements. For the same reasons, financial institutions were wary of funding geothermal energy projects. Development of the large resource base in the United States, apart from The Geysers in California, was essentially stagnant. This was the environment in which the U.S. Government's geothermal research and development (R&D) program began.

The intent of the geothermal program was to understand geothermal resources, improve geothermal science and engineering technology, and ensure that information was publicly available to geothermal stakeholders, such as developers, utilities, financial institutions, regulators, and others necessary to spur development of a vital, progressive geothermal industry. As this report will demonstrate, the intent was achieved, to the benefit not only of geothermal energy development in the United States but also around the world.

This report is one of a series issued by the U.S. Department of Energy (the Department) to document the many and varied accomplishments stemming from the government's sponsorship of geothermal research since 1976. The report represents a history of the major research programs and projects that have had a lasting impact on the use of geothermal energy in the United States and those that promise to have an impact. We have not attempted to write the definitive history of the Geothermal Technologies Program and the \$1.3 billion that were expended through 2006 on geothermal research. Rather, we have brought together the collective memories of those who participated in the program to highlight advances that the participants deem worthy of special recognition.

In particular, this report examines the work done in one key area of geothermal technology development: Energy Conversion. Companion reports cover work in other areas, including Drilling, Exploration, and Reservoir Engineering. The history focuses on the period from 1976 to 2006, when the Department was the lead agency for geothermal technology research as mandated by the Geothermal Research, Development, and Demonstration Act of 1976. The earlier groundbreaking work by precursor agencies, such as the National Science

Foundation, Atomic Energy Commission, U.S. Geological Survey, and the Energy Research and Development Administration, is cited as appropriate but is by no means complete.

Those who wish to learn more about certain topics discussed herein should consult the references listed in the report. These sources give the reader access to a much larger body of literature that covers the topics in greater detail. Another useful source of information about the Department's geothermal research can be found in the Geothermal Technologies Legacy Collection (www.osti.gov/geothermal/) maintained by the Office of Science and Technology Information.

The budget history of the federal geothermal research program during the 30-year period documented here is included as Appendix A. That portion of the budget devoted to energy conversion is highlighted and amounts to about \$320 million in actual dollars. Funding for work in energy conversion ended in fiscal year 2006 with a decision by the Department to refocus limited funding resources on higher priority needs within the Office of Energy Efficiency and Renewable Energy. That decision does not preclude future work in this area, as the needs for geothermal technology development are assessed. This report documents the products and benefits of that earlier research investment.

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While the many contributors to U.S. Department of Energy-supported geothermal energy conversion research and development over the years are too numerous to acknowledge by name, we wish to mention those who participated in writing this report. The primary author was Gregory L. Mines of the Idaho National Laboratory, for many years a principal investigator in the energy conversion program. Contributors include Carol J. Bruton, Ph.D., Lawrence Livermore National Laboratory (retired); R. Gerald Nix, Ph.D., National Renewable Energy Laboratory (retired); and from Brookhaven National Laboratory, Thomas A. Butcher, Ph.D., Lawrence E. Kukacka (retired), and Eugene T. Premuzic, Ph.D. (retired). Elizabeth C. Battocletti and Allan Jelacic served as the report's technical editors. These persons deserve credit for assembling a history of impressive accomplishment that will continue to reap benefits for many years to come. To the individuals whose efforts are not specifically identified in this report, the Department and authors offer their sincere gratitude.

Introduction

This report summarizes significant research projects performed by the U.S. Department of Energy (DOE)'s Geothermal Technologies Program¹ over the past 30 years to overcome challenges in energy conversion and make geothermal electricity more cost-competitive. At the onset of DOE's efforts in the 1970s, several national laboratories, universities, and contractors conducted energy conversion research. Since the 1980s, work was primarily conducted at Brookhaven National Laboratory (BNL), Idaho National Laboratory (INL), Lawrence Livermore National Laboratory (LLNL), and National Renewable Energy Laboratory (NREL).² While this document discusses research done in the 1970s, emphasis has been placed on work done since the 1980s.

When DOE's energy conversion research and development (R&D) program began, commercial power production from geothermal resources in the United States was limited to The Geysers, a dry-steam field located in northern California. No commercial facility in the United States used liquid-dominated resources for power production. In order to support its research activities, DOE developed test facilities in California at the Salton Sea, East Mesa, and Heber; in Idaho at Raft River; and later in Texas at Pleasant Bayou. At selected DOE facilities, power plants were constructed incorporating the "first use" of specific technologies, including multiple boiling binary cycles, supercritical binary cycles using working fluid mixtures, and hybrid cycles for geopressured-geothermal resources. In addition to national laboratory and university researchers, DOE also contracted with the geothermal industry to conduct research at these facilities. Developing the technologies to improve the economic feasibility of using liquid-dominated resources for power production was, and remains, the primary goal of DOE's energy conversion R&D activities.

Increasing interest in developing geothermal resources in southern California's Imperial Valley resulted in early research efforts concentrated on identifying materials and plant components that were compatible with the hot, corrosive, mineral-laden fluids found in the valley. Research efforts also focused on developing techniques for handling these fluids. While a wide range of activities was conducted in the early research period, primary emphasis was placed on understanding geothermal fluid chemistry and developing materials and components such as heat exchangers. Geothermal fluids produced from liquid-dominated resources are hot and may contain significant levels of dissolved solids with a higher potential for corrosion and scaling. Identifying compatible materials and minimizing the precipitation of dissolved solids are important in determining the feasibility of using liquid-dominated resources for power production.

In 1978, the U.S. Geological Survey (USGS) performed an assessment³⁻⁴ that indicated a greater abundance of lower temperature geothermal resources. As a result, focus was increasingly placed on developing binary cycle technologies for low-temperature conversion. Because power production potential varies directly with the resource temperature, the economic feasibility of power production from these resources was deemed marginal at best. Consequently, DOE began to emphasize developing binary cycle technologies in order to improve the economic viability of using lower temperature resources to generate power. DOE research in the 1980s and 1990s focused on technologies to improve the performance of binary power cycles.

Two energy conversion systems have emerged for power production using liquid-dominated geothermal resources. For higher temperature resources, the flash-steam power cycle is favored (Figure 1). In this cycle, the pressure of the geothermal fluid is reduced until the fluid begins to boil, or flash. The flashed steam is separated from the liquid and expanded through a turbine coupled to an electric generator. The un-flashed liquid is injected back into the reservoir. The flash-steam power cycle has several advantages: 1) the corrosive and scale-prone liquid, or brine, is not exposed to the main plant components (turbine and condenser); 2) the steam condensate can be used for make-up in an evaporative heat rejection system; and 3) the cycle is relatively simple to engineer. While a flash-steam plant had yet to be built in the United States by the mid-1970s, the technology was being used commercially in New Zealand, Japan, the then-Soviet Union, and Mexico.⁵

The other conversion system, the binary cycle, is commonly used in low-temperature applications, but is becoming increasingly popular with medium- and even high-temperature geothermal resources (Figure 2). In a binary cycle, heat is transferred from the geothermal fluid to a secondary working fluid. In this heat transfer process, the working fluid—usually a hydrocarbon with a low boiling point—is vaporized. The pressurized vapor is then expanded through a turbine coupled to an electric generator. The expanded working vapor is cooled, condensed, and pumped back to the geothermal heat exchangers to complete the closed working fluid loop. The binary cycle has certain advantages. The geothermal fluid is never exposed to the ambient environment, all geothermal fluid produced is reinjected, and the cycle has potential for greater power production from a given geothermal fluid flow. In the early 1970s, the binary conversion cycle for geothermal power generation was only used at a small plant in the then-Soviet Union.⁵

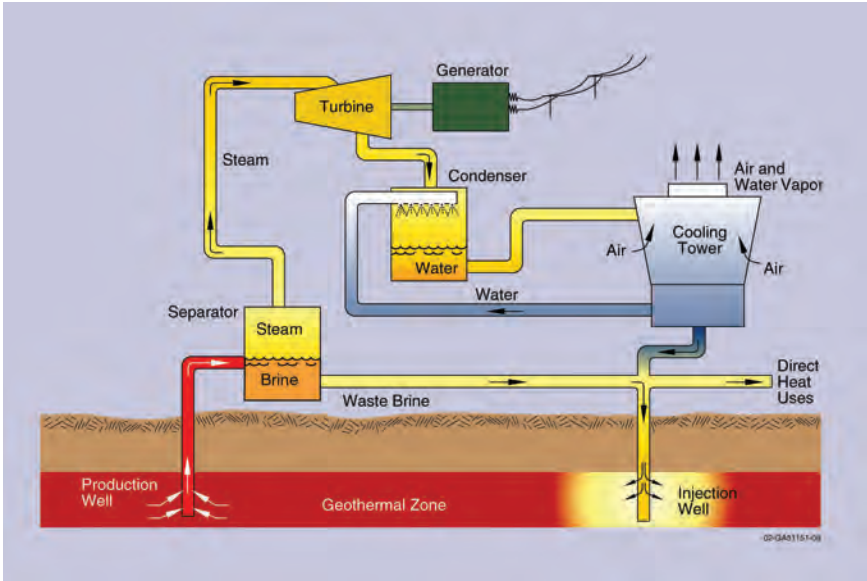


Figure 1. Flash-steam geothermal power plant

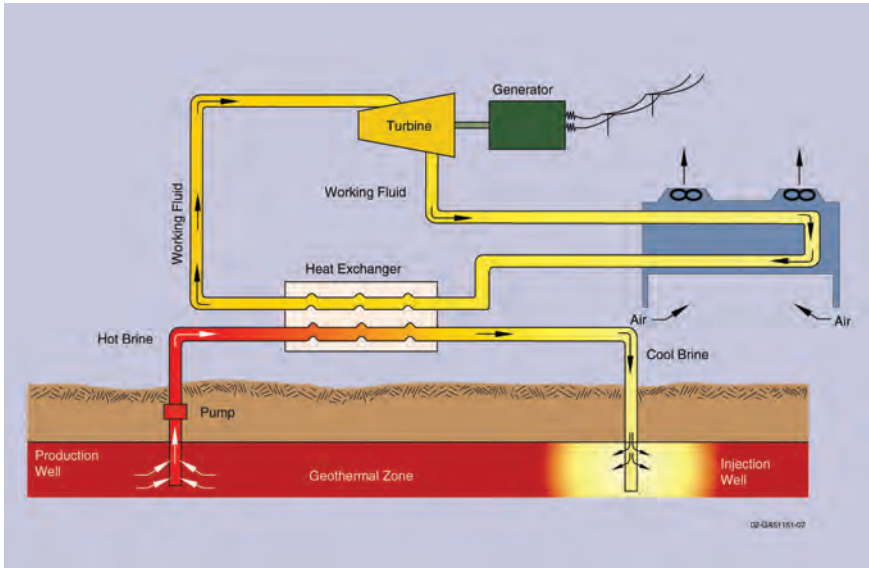


Figure 2. Binary cycle geothermal power plant

As the geothermal industry began to build commercial plants using liquid-dominated resources, field validation of technologies shifted from DOE facilities to commercial geothermal power plants. By the early 1990s, all DOE-supported test facilities were closed. National laboratory investigators worked closely with industry on field validation of technologies to improve the economic feasibility of power production. Increased interaction with industry resulted in identifying technology improvements for the operation and maintenance (O&M) of geothermal power plants, including those using vapor-dominated resources. DOE addressed these O&M issues through direct cost-shared research with industry, as well as through research by national laboratories and universities working in partnership with industry. DOE R&D worked to lower power generation costs through research and development in several areas including:

- Longer lasting materials that are easier to replace or repair.
- Improved methods for handling highly corrosive and scale-prone fluids.
- More efficient conversion cycles.
- Innovative components that have improved performance and lower costs.
- More robust power conversion systems that can accommodate time-variant resources and ambient conditions.
- Improved instrumentation that provides real-time monitoring of plant processes.

Energy conversion research performed through DOE contributed to the introduction of new “game changing” advances including:

- Binary conversion cycles allowing access to lower temperature resources.
- Understanding geochemistry in energy conversion systems that use highly saline brines—such as those found at the Salton Sea—which has resulted in over 300 megawatts (MW) of power production.
- Conversion efficiency improvements using better components, including the Advanced Direct Contact Condenser that increased a plant’s output by five percent.
- Removal of air from binary working fluid systems, increasing plant output by four percent and reducing hydrocarbon losses by several orders of magnitude.
- Coatings like polyphenylene sulfide which, when applied to a carbon steel base, provide corrosion resistance for inexpensive construction materials and improve performance.
- Innovative instruments to enhance plant operability, including a new technology for monitoring both steam quality and mineral scaling of internal turbine surfaces.

Accomplishments and Impacts

At the inception of DOE's energy conversion research activities in the 1970s, The Geysers in northern California was the only operating geothermal power plant in the United States. It had a power plant capacity of 396 MW.⁵ Thirty years later, at the end of 2004, U.S. geothermal power installed production capacity totaled 2,534 MW,⁶ of which 1,100 MW was generated from liquid-dominated resources outside of The Geysers. Of this total U.S. installed capacity, just over 2,000 MW of power was delivered for sale. Much of this growth occurred in the 1980s and early 1990s when DOE's funding for research activities was higher than current levels. While it is impossible to directly tie growth in geothermal power to specific research activities, DOE's research on energy conversion undoubtedly contributed to the development of specific geothermal resources.

The Salton Sea geothermal resource in California's Imperial Valley is the second most significant geothermal power producer in the United States. According to the Geothermal Energy Association (GEA), geothermal power plants in the Salton Sea produce approximately 335 MW from this very hot (265°C [509°F]), very saline (> 200,000 part per million [ppm]) resource. DOE supported the early development of the brine acidification and reactor-clarifier technologies used in the Salton Sea power plants. In fact, without this DOE research, development of the Salton Sea geothermal resource would have been significantly delayed.

Researchers supported by DOE repeatedly demonstrated a number of technology "firsts" that have subsequently been adopted by industry. Examples include:

- The first binary cycle geothermal power generated in the United States was accomplished with small prototype plants whose design, construction, and operation were supported by DOE.
- The improvement in binary cycle performance, which resulted from boiling the working fluid at multiple pressures, was successfully demonstrated at DOE's 5-MW Binary Pilot Plant at Raft River in Idaho.
- Early DOE researchers were the first to use downhole pumps to increase production from geothermal wells. Though early efforts were not very successful, techniques were developed that extended pump operating life. The Raft River facility successfully used a downhole lubrication system for line-shaft pumps. This system has been widely adapted by the industry.
- Automated, unattended operation of small binary plants was demonstrated at the Raft River Prototype Plant.

Over the years, the U.S. geothermal industry has frequently adopted or adapted DOE-supported technologies, leading to commercial use of these technologies in geothermal plants. For example, industry adapted the automated plant control pioneered by DOE, adding an automatic restart capability. Another example is industry's use of "cascaded" (i.e., plants installed in series) modular plants to improve performance. This use of modular plants in series produces the same performance improvement as the dual-boiling cycle first demonstrated at the Idaho DOE Raft River pilot plant in 1981. Today, approximately 40 percent of the binary power plants in the United States employ the concept of boiling at more than one pressure to increase performance.

DOE also supported research to mitigate concerns and risks associated with developing liquid-dominated resources. This included early investigations that showed power plants using low- to moderate-temperature liquid-dominated resources could use carbon steel as the construction material. This work found that corrosion and fouling of heat exchangers by geothermal fluids was not as extensive as previously thought. While these results were not directly incorporated into specific plant designs, they established the adequacy of carbon steel and the probability of low fouling factors, alleviating some of the risk in using carbon steel. By using carbon steel instead of stainless steel for geothermal heat exchanger tubes, heat exchanger capital costs could be reduced by over 50 percent and total plant capital costs by up to 10 percent.⁷

In addition, DOE research targeted plant-specific processes and issues, resulting in new technologies to address particular problems. The benefits of these new technologies are difficult to quantify because they may not be relevant to all geothermal plants. Frequently, benefits for a particular plant lie in what is avoided, e.g., equipment repair or replacement and the loss of power sales revenue from a plant shutdown. Examples of new technologies supported by DOE include:

- The decline in a resource's production capacity may be offset by modifying turbine inlet conditions and allowing expansions into the two-phase regions. This concept was demonstrated at a DOE test facility and was subsequently incorporated into binary plant operations, resulting in increased power generation of up to 10 percent at some facilities. (Section 4.2.1)
- Carbon steel, widely used in geothermal power plant construction, is subject to corrosion. DOE conducted research to develop non-metallic coatings for carbon steel that provide the same corrosion protection as more exotic and expensive alloys. The work performed by researchers at BNL and NREL received R&D Magazine's prestigious "R&D 100 Award" in 2002. The "Smart, High-Performance Polyphenylenesulfide (PPS) Coating System" won a Federal Laboratory Consortium Award in May 2003. (Section 2.2)
- Geothermal fluids contain noncondensable gases (NCGs), which collect in the condensers of steam plants and decrease performance. An advanced direct

contact condenser for steam plants was developed and demonstrated at The Geysers, resulting in an increased power output of 5 percent. The technology earned an “R&D 100 Award” in 1999 for NREL, the Alstrom Corporation, and Pacific Gas and Electric Company, and is currently licensed to Alstrom. (Section 4.1.4)

- While not typical, NCGs may also be an issue for binary plants. A removal system was developed and demonstrated using membrane separation technology to significantly reduce the level of gases, increase power output by 4 percent, and reduce working fluid losses by factors of 10 to 20 at binary plants. INL licensed the technology to Membrane Technology and Research, Inc. (MTR). (Section 5.2)
- DOE-supported energy conversion research found a more effective way to measure the moisture level of steam entering turbines. The new method provided continuous, in situ measurement of steam quality and was substantially more sensitive than commercially available instrumentation. In addition, the technology could also be useful in identifying scaling of internal turbines before significant degradation in turbine efficiency occurs. INL licensed this technology to Thermochem. (Section 5.1.1)
- A commercially available instrument for monitoring microbial activity in fire protection systems was adapted to continuously monitor the development of biofilms in geothermal power plants. (Section 5.1.2)
- BNL and LLNL developed and demonstrated methods of recovering silica from geothermal fluids. Mineral recovery is a potentially significant revenue stream for some geothermal power plants. The technology earned an “R&D 100 Award” in 2001. (Section 3.3)
- DOE-sponsored energy conversion R&D received such additional recognition as:
 - Commendation from DOE for Geothermal Work Dealing with Brines and Residues (Geothermal Division), 1991.
 - Environmental Achievement Awards from the National Awards Council for Environmental Sustainability, 1997 and 1998.
 - “R&D 100 Award,” ThermaLock Cement, 2000.
 - American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Crosby Field Award for Best Paper and ASHRAE Poster Presentation Award for “Thermal-Conductivity of Cementitious Grouts and Impact on Heat Exchanger Length Design for Ground Source Heat Pumps,” 2000.
 - Geothermal Resources Council (GRC), Special Achievement Award

for Outstanding Contribution to the Development of Geothermal Resources, 2001.

In addition, DOE sponsored several definitive analyses of energy conversion systems which remain widely in use today by industry, DOE researchers, and others, including:

- Radian Corporation developed material selection guidelines for geothermal conversion systems using data collected by DOE researchers and industry. The study included fluid chemistries, material test results, and operating experiences for several geothermal resources in the United States. Rates for different corrosion processes were summarized for the materials tested at each resource, along with discussions of the suitability of these materials for different plant applications at that resource. The guidelines were published as “Material Selection Guidelines for Geothermal Energy Utilization Systems” in 1981.⁸
- Brown University published two books reflecting the accumulated knowledge of 39 participants representing the U.S. Government, academia, industry, and national laboratories, each with unique expertise on different aspects of geothermal power plants. “Geothermal Energy as a Source of Electricity”⁵ summarizes geothermal power plant operations worldwide. “Sourcebook on the Production of Electricity from Geothermal Energy”⁹ is the authoritative reference on the technologies needed to produce power from geothermal energy. While both were published in 1980, much of the information remains relevant and useful today.
- In the 1990s, a consortium of industry and government agencies, including DOE, supported a study of the performance and cost of flash-steam and binary power plants at eight locations. The study examined how advanced energy conversion technologies that could be used in the near future would impact cost and performance. The resulting Electric Power Research Institute (EPRI) report, “Next Generation Geothermal Power Plants,” was published in 1995.¹⁰

Furthermore, DOE researchers routinely presented their findings at the GRC annual meeting, at other technical conferences, and in journals.

Conversely, industry has not yet adopted some technologies resulting from DOE-supported research primarily because market conditions have not been conducive to their use. Examples of such technologies include:

- Direct contact heat exchangers and fluidized bed heat exchangers are used to transfer heat from hot brines to working fluids. In the late 1970s and early 1980s, direct contact heat exchangers were successfully used in small operating binary plants at both East Mesa in California and Raft River

in Idaho. When it became apparent that the lower temperature resources generally had relatively benign fluids, these heat exchangers types were deemed not cost-effective.

- In 1987, power was generated from a geopressured-geothermal resource in Texas at the Pleasant Bayou hybrid binary plant using both the heat and a portion of dissolved methane from the fluid. While technologically successful, the plant was uneconomic relative to the cost of power generated from conventional gas turbines. Recent increases in gas prices provide greater economic incentive to develop this resource.
- The use of supercritical cycles and mixed working fluids to improve performance were identified as promising, and validated in testing at DOE's Heat Cycle Research Facility near Heber, California in the mid-1980s. Though the degree to which performance can be improved is dependent upon what basis is used for the comparison, improvements of up to 20 percent were expected. For scenarios where plant and well field development costs are equivalent, reductions in power generation costs of up to 10 percent were projected. Despite the low risk associated with adapting these technologies,⁸ they have yet to be used in any commercial plant.
 - The development of the very large geothermal resource base associated with Enhanced Geothermal System (EGS) technology¹¹ presents a significant opportunity to use these advanced cycle concepts. EGS will likely incur higher well field development costs in drilling to greater depths and in creating a subsurface fracture-heat exchange system to extract the heat from the native rock. The added costs to develop the resource and well field will justify the use of the advanced cycle concepts.

Table 1 summarizes the major advances resulting from DOE R&D in energy conversion from 1976 through 2006. Advances are not ranked in any particular order of importance or priority. Each has significantly contributed to fulfilling the goals of the federal geothermal energy conversion R&D activities.

Table 1. Major advances resulting from the U.S. Department of Energy's geothermal energy conversion R&D programs, 1976 – 2006

Technical Area	Accomplishment	Significance	Industry Measure
Improved Conversion Cycles	Demonstrated viability of binary cycles	Made lower temperature resources commercial	Approximately 270 MW (nameplate) of installed capacity in the United States (GEA)
	Demonstrated benefit of multiple boiling power cycles	Improved performance and economic viability of binary cycles	Used in approximately 40 percent of binary power production in the United States
	Confirmed no damage or performance penalty from metastable turbine expansions	Improved plant performance, especially with declining resource productivity	Incorporated into operation at binary plant complex at Mammoth Lakes, California, with power output increases of up to 10 percent
	Confirmed performance benefits from supercritical cycles with mixed hydrocarbon working fluids	Increased performance up to 20 percent	No commercial use Probable cycle for EGS development
Enhanced Operability	Better understanding of brine geochemistry	Clarifier and pH modification allows power generation from hyper-saline fluids	Salton Sea has an installed capacity of over 325-MW (flash) with bottoming cycles used at Blundell Utah (GEA)
Improved Components	Advanced direct-contact condenser (ADCC)	Reduced cost and increased output	ADCC increased capacity of Unit 11 at The Geysers by 5 percent; technology is licensed
	Binary plant noncondensable gas removal system	Increased power generation by about 4 percent and reduced working fluid losses	Successfully demonstrated in two operating plants; technology is licensed
	Enhanced air-side heat transfer performance of air-cooled condenser	Allows condenser size to be reduced or additional power generated (3 to 4 percent increase in power or decrease in plant cost)	Technology successfully demonstrated at bench scale; researchers working with heat exchanger industry to commercialize technology

Technical Area	Accomplishment	Significance	Industry Measure
Reduced Maintenance	Better materials such as PPS-coated carbon steel	Reduces cost and improves maintainability	PPS can reduce the levelized cost of electricity (LCOE) by up to 0.5¢ per kilowatt-hour (kWh)
	Demonstrated means of monitoring microbial activity in power plant cooling waters	Reduces cost and improves maintainability	Potential reduction in LCOE of 0.1 to 0.2 ¢/kWh; technology is commercially available
	Demonstrated use of improved steam quality monitor	Provides more sensitive, in situ, real-time monitoring of steam quality	Potential reduction in LCOE of 0.1 to 0.2 ¢/kWh; technology is licensed

Major Research Projects

DOE energy conversion research activities at the national laboratories ran from 1973 through 2005. This document provides summaries of those activities that took place over 30 years of research. This research is summarized in the following focus areas:

1. DOE test facilities and demonstration plants
2. Materials development
3. Geothermal fluid chemistry
4. Power plant design and engineering
5. Power plant operations
6. Power plant analytical studies.

In general, the research summary in each of these areas is given in chronological order.

1.0

DOE Test Facilities and Demonstration Plants

One of DOE's key objectives was to conduct research using actual geothermal fluids whenever possible. In the early 1970s, however, few liquid-dominated resources had been developed to the extent that researchers could access actual produced geothermal fluids. Consequently, to support its research activities, DOE developed government-owned test facilities at the Salton Sea and East Mesa in California, at Raft River in Idaho, and later at Pleasant Bayou in Texas. As hydrothermal resources were developed for power production, the emphasis changed with research increasingly conducted at commercial facilities in cooperation with industry. By the early 1990s, all DOE-sponsored test facilities were shut down and decommissioned.

In addition to test facilities, DOE also funded the design and construction of demonstration geothermal power plants. Two of the larger plants built were in Idaho at Raft River and in California at Heber. Raft River was a 5-MW binary plant using a 140°C (284°F) resource. The Heber plant was designed to produce 45 MW_{net} from a 182°C (360°F) resource, also using binary cycle technology. Heber was developed with support from DOE, San Diego Gas and Electric (SDG&E), EPRI, and several other organizations. Unlike Raft River, the Heber geothermal reservoir was owned, developed, and operated by Chevron Geothermal Company and Unocal Geothermal, independently of the power plant.

In addition to the above projects, a large, 50-MW flash-steam demonstration plant was planned at the Baca Ranch in New Mexico with Unocal Geothermal and Public Service Company of New Mexico as industry partners. The Baca project was abandoned after exploratory drilling did not confirm sufficient steam production to power the plant. DOE also funded the design, construction, and operation of smaller plants at its test facilities, including the hybrid plant at Pleasant Bayou in Texas, which used a geopressured-geothermal resource to generate power.

1.1 Raft River, Idaho

Efforts at Raft River began in the early 1970s—the first well was drilled in 1975. The USGS supervised geological work, resource assessment, and drilling. INL (formerly known as Idaho National Engineering and Environmental Laboratory [INEEL]) was the primary lead for R&D activities at Raft River and was responsible for all facility operations. Additional wells were drilled and on-site facilities were developed, which supported a variety of experiments—a number

of which focused on direct-use applications (e.g., aquaculture, food and process drying, production of alcohol, etc.). Most DOE energy conversion R&D activities were conducted to support a planned 5-MW binary plant; discussion of some of those activities is included in the Materials Development section of this document.

1.1.1 Prototype Power Plant

As part of the DOE efforts at Raft River, a small prototype power plant was built in support of the design of a larger 5-MW plant that was subsequently constructed. The prototype plant operated intermittently from the spring of 1978 through 1982. The plant used an isobutane working fluid and a simple, single boiling cycle, with a water-cooled condenser. It provided insight into the operation of a binary plant, later serving as a test bed for examining innovative concepts and components for the proposed next generation plant at Raft River. Originally referred to as the “60-kW Binary Plant,” the plant later became known as the “Prototype Power Plant” when used for research activities not in direct support of the 5-MW pilot plant.

As part of initial testing, the prototype power plant was operated continuously in an un-manned mode over a five-month period in 1979.¹² This testing confirmed the plant’s operational stability, even during periods when geothermal fluid flow rates and temperatures changed. It also validated the feasibility of designing a plant to operate in an automatic, un-manned mode.

The facility was later used to test a sieve tray direct contact heat exchanger,¹³ and served as a test bed for Oak Ridge National Laboratory’s (ORNL) fluted-tube condenser. The plant was subsequently modified to test supercritical cycles with mixtures. With the termination of operations at Raft River, the equipment was moved to DOE’s East Mesa test facility in southern California, becoming part of the Heat Cycle Research Facility (HCRF).

1.1.2 Raft River 5-MW Binary Pilot Plant

In the late 1970s, DOE decided to construct a larger binary power plant at Raft River. The 5-MW plant began producing power from the 140°C (284°F) Raft River resource in 1981.¹⁴ The plant used an isobutane working fluid in a dual boiling cycle. This was the first use of multiple levels of boiling in a binary cycle used to increase plant performance. A photo of the Raft River plant is shown in Figure 3. The low- and high-pressure pre-heaters and kettle boilers are in the foreground.



Figure 3. Raft River 5-MW binary pilot plant, Idaho

The Raft River 5-MW plant, one of the first binary plants built in the United States, was used to validate the adequacy of engineering tools and methods in sizing and predicting the performance of binary plant components (e.g., heat exchangers, condensers, and turbines). Researchers worked with Heat Transfer Research, Inc. (HTRI) to assess the adequacy of the heat exchanger design codes, and with the University of Oklahoma and the University of Utah to obtain property codes to predict thermodynamic and transport properties.

Prior to plant start-up, tests were conducted with both electric submersible and line-shaft pumps in the production wells; the latter were subsequently used. Line-shaft pumps provided a longer operating life with the adaptation of a down-hole lubrication system developed for the line shaft bearings. Submersible pumps were found to be unreliable, especially with repeated pump shutdowns and restarts.

Anticipating that legal rights would be secured to use surface or near-surface water for cooling water make-up, the Raft River plant featured an evaporative heat rejection system with a water-cooled condenser. When such legal rights were not obtained, cooled geothermal fluid was used for make-up to the heat rejection system.¹⁵ While other facilities had used cooled geothermal fluid to augment a sensible heat rejection system, this is the only known application where the cooled brine provided the only source of make-up for an evaporative heat rejection system. Pre-treating cooled geothermal fluid was labor intensive and used large amounts of chemicals.

High operating costs, combined with the northwestern states' abundant, low cost hydropower, resulted in the plant's shutdown in 1982 when participating utilities declined to take over and continue operation of the plant. The site was "mothballed" and the plant sold by DOE in 1984. U.S. Geothermal, Inc. acquired the resource in 2002 and is selling 10 MW of electricity from the Raft River Unit 1 power plant to the Idaho Power Company.¹⁶

1.2 Geothermal Components Test Facility

The Geothermal Components Test Facility was located in the East Mesa area of California's Imperial Valley. The facility was initially part of a Bureau of Reclamation desalination project. In 1976, the facility was expanded to provide the Energy Research and Development Administration (ERDA) and later DOE¹⁷ with a test facility for investigating geothermal conversion system equipment, brine chemistry, and materials. Lawrence Berkeley National Laboratory (LBNL) managed the facility operations during this period. In 1978, DOE became the exclusive operator of the facility, which was subsequently referred to as the Geothermal Test Facility (GTF). By the mid-1980s, the INL HCRF was the only experimenter still at the GTF. When geothermal fluid supply became inadequate, the HCRF was moved to the B.C. McCabe plant¹⁸ location in 1988, ending experimental activities at the GTF.

While in operation, the GTF was open to anyone with equipment to test, including lab researchers, industry, universities, and other government agencies. Three major facility projects are summarized in the subsequent paragraphs:

1. The 500-kW Direct Contact Pilot Plant.
2. The Sperry Gravity Head Cycle Demonstration Plant.
3. The East Mesa Geothermal Pump Test Facility.

Additional DOE-supported activities at the GTF are described in the Materials Development, Geothermal Fluid Chemistry, and Component Development Projects sections.

1.2.1 500-kW Direct Contact Pilot Plant

In 1979, a binary pilot plant was constructed at the GTF utilizing a direct contact heat exchanger to heat and vaporize an isobutane working fluid. The plant was designed, constructed, and operated by Barber-Nichols Engineering under contract to LBNL.

The direct contact heat exchanger (DCHX) used a spray tower configuration, where cold isobutane working fluid entered near the bottom of the DCHX. The isobutane passed through a perforated plate to form droplets that were then heated as they rose through the heavier, down-flowing geothermal fluid. These droplets vaporized in the upper portion of the DCHX where the brine was introduced. Before entering

the DCHX, brine pressure was lowered until the fluid began to flash. This was done to remove NCGs before they could contaminate the working fluid system.¹⁹

The initial plant configuration employed evaporative condensers. The working fluid was condensed inside of tubes; both water and air were passed over the outer condenser tube surfaces. The plant used a working fluid recovery system to minimize the loss of isobutane dissolved or entrained in the geothermal fluid leaving the plant. A photo of the plant is shown in Figure 4. The DCHX is the large vertical vessel in the middle of the photo. The brine handling equipment is to the left of the DCHX, and the condensers are to the right.

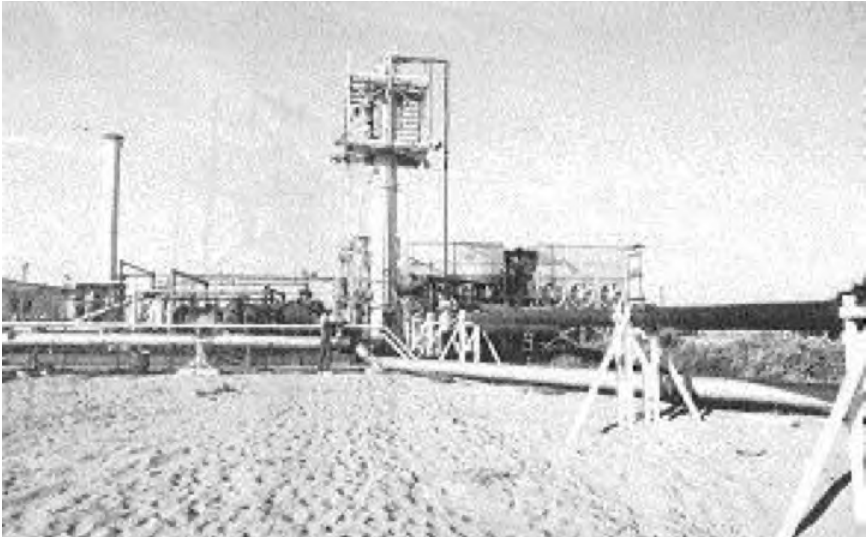


Figure 4. 500-kW direct contact pilot plant

With the exception of the turbine, the plant equipment met or exceeded expected performance in spite of higher-than-anticipated levels of carbon dioxide (CO₂) in the geothermal fluid.²⁰ The DCHX performance testing yielded smaller internal approach temperatures (0.6°C to 2.1°C [1.1°F to 3.7°F]) than design (3.9°C [7.0°F]), suggesting little internal recirculation had occurred. The operation was stable, and no significant control issues were encountered. Turbine failures experienced during the plant's early operation were resolved by correcting a mechanical design fault. Applying a commercial-scale inhibitor in the geothermal fluid before it entered the plant solved scaling problems.

A submersible pump was used in the production well supplying the plant. Pump reliability issues were resolved by installing a surface-mounted oil pressurization system that kept the submersible pump motor pressurized. This significantly

extended the pump life; the pump operated for approximately 8,000 hours before wear on the pump stages due to formation sand became excessive. This was the first successful use of an electrical submersible pump in a geothermal application.

1.2.2 Sperry Gravity Head Cycle Demonstration Plant

In 1978, DOE began funding the development of a full-scale well head power plant to demonstrate the gravity head geothermal energy conversion system being developed by Sperry Corporation. In this binary conversion cycle, heat transfer between the geothermal fluid and the working fluid occurred in the well bore where the working fluid flowed in tubing down the well. At the bottom of the heat exchanger, the heated working fluid was expanded through a turbine that is directly coupled to the geothermal production pump. The high temperature, high pressure working fluid exiting this turbine flowed back to the surface through a central riser. Back at the surface, the working fluid was expanded in a conventional turbine, condensed, and returned to the well head. Because of the density head of the working fluid in the well, little, if any, working fluid pumping power is required to maintain the working fluid circulation in the loop. The avoidance of this parasitic load is the main performance advantage of the Sperry gravity head cycle over the conventional binary cycle.²¹ A schematic of the Sperry gravity head cycle is shown in Figure 5.

Work to locate the Sperry facility at the GTF began in 1980, with site preparation followed by delivery and installation of the “surface” equipment. Drilling of Well 87-6, which would be used for the demonstration project, also began in 1980. Numerous problems occurred in drilling the well to a depth of 6,274 feet, including difficulty setting the two large casing strings in the upper portion of the well, unexpected returns during the cementing of casing, and apparent lost circulation. Difficulties were subsequently encountered in trying to kill the well (i.e., placing a column of heavy fluid into a well bore in order to prevent the flow of reservoir fluids without the need for pressure control equipment at the surface), apparently due to a serious casing leak. An attempt to salvage the well by putting in a thin-walled liner in the upper portion of the well failed when the liner collapsed. At this point construction activities were terminated, even though the surface equipment had been installed and the downhole assembly was ready for installation in the well. Following DOE’s decision in July 1981 to end its involvement, the well was plugged and abandoned. Sperry’s efforts to obtain funds to drill another well at the location were unsuccessful, and the project was eventually terminated.

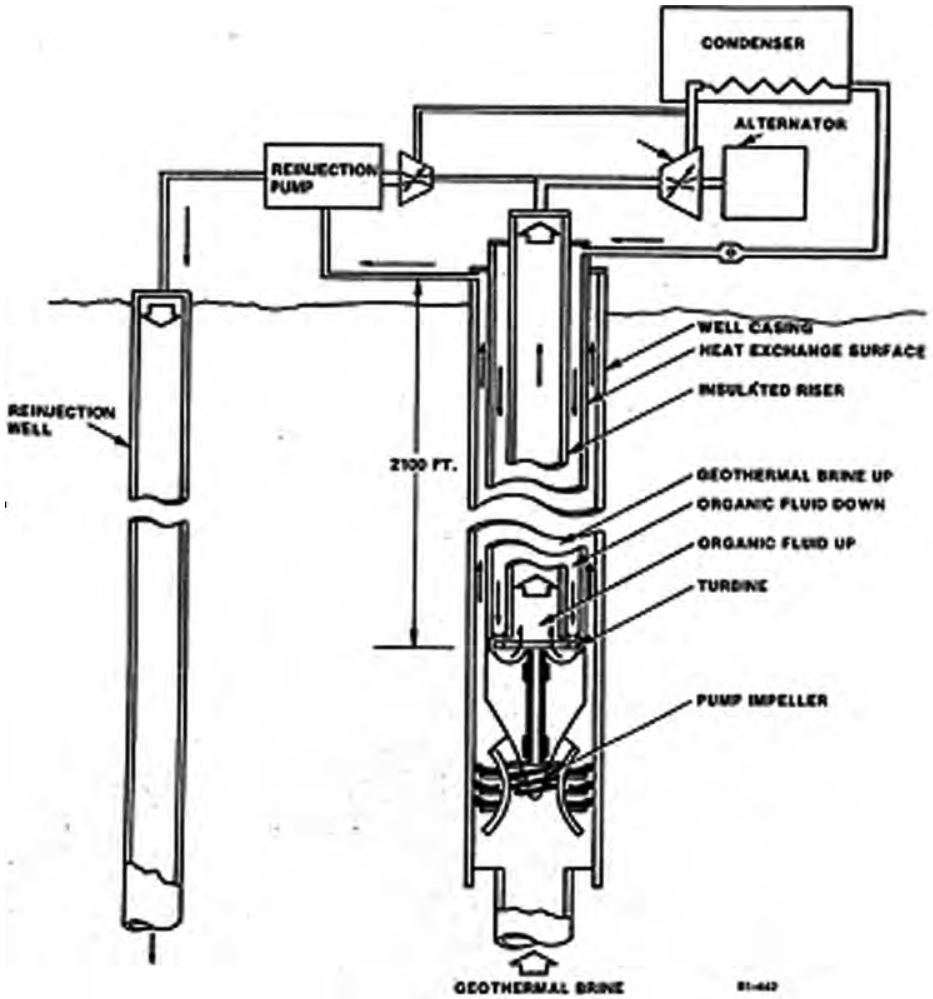


Figure 5. Schematic of Sperry gravity head system

1.2.3 Geothermal Pump Test Facility, East Mesa

As the temperature of a geothermal resource decreases, the amount of fluid required to produce a given level of power increases. For power to be generated from lower temperature resources, down-hole pumps are needed to increase flow from production wells. Because an electric submersible pump can be set deeper in the well, it has greater potential to provide the higher flow rates needed. To facilitate the development of these pumps for geothermal applications, DOE contracted with Barber Nichols Engineering to design and construct a test facility for down-hole pumps. In 1982, the Geothermal Pump Test Facility (GPTF) was constructed at the GTF.²²

Pump manufacturers were to use the GPTF to conduct in-the-well testing at typical geothermal operating conditions without the risk of putting a submersible pump in an actual well. The GPTF consisted of a brine control module, a test section located 160 feet below ground, a hydraulic turbine for power recovery, and a gantry-mounted hoist for pump handling. The facility was capable of testing pumps from 70 to 750 horsepower. The fluid used in the testing was supplied from one of the GTF wells. Following construction, the declining geothermal budget could not support DOE's testing of production pumps. Although the facility was available for use by pump manufacturers and other entities, the GPTF was not used for any further testing.

1.3 Geothermal Loop Experimental Facility

The Geothermal Loop Experimental Facility (GLEF) was completed in 1976 in California's Imperial Valley to examine the technical and economic feasibility of using high-temperature, hyper-saline brines produced from the Salton Sea resource. GLEF was a cost-shared project between SDG&E and ERDA/DOE. The geothermal fluid was provided by Imperial Magma and New Albion Resource Company. LLNL conducted R&D activities at GLEF and provided direct technical support to the facility operation. The Bureau of Mines also conducted material investigations at the facility to identify materials most suitable for power plant design and operation with these fluids.²³

The geothermal fluid used by the GLEF had a well head temperature of 191°C (375°F) and a pressure of about 150 pound-force per square inch gauge (psig). The total dissolved solids (TDS) exceeded 200,000 ppm and the noncondensable gas levels were about 3 percent by weight. Production wells were located near a region that had previously been used for CO₂ production. Concerns that produced fluids could have excessively high levels of CO₂ (a noncondensable gas) contributed to the original decision to use a hybrid flash-binary power cycle at the GLEF.

The GLEF was originally configured as a four-stage flash-binary pilot plant, with steam produced by flashing the brine at four different pressures. The

steam produced by flashing was used to preheat and vaporize the binary cycle's working fluid. The high-pressure working fluid (distilled water in this case) leaving the vaporizer was then expanded across a throttling valve, with the provision that this valve could be replaced by a 10-MW turbine. Scaling in the brine system, process oscillations, lower-than-expected NCG content, and brine supply problems all hampered early operation. In 1978, the GLEF was modified, and the plant's brine portion was converted to a double-flash system. Subsequent testing emphasized the brine or liquid portion of the plant.

Later modifications allowed for testing an effluent brine treatment system (clarifier-filter). The reactor clarifier process was used to accelerate the silica precipitation through rapid mixing and seeding with previously precipitated silica particles. The precipitated solids formed a sludge on the bottom of the clarifier that flowed to a thickener where the solids were further concentrated before being pumped to a filter press to remove water. The liquid leaving the clarifier was passed through a sand-and-anthracite filter to remove any suspended solids before the fluid was injected.

Testing and operation at the GLEF was concluded in the fall of 1979, completing a test program focused on finding solutions to issues associated with handling a geothermal fluid with extremely high potentials for both scaling and corrosion.²⁴ Additional discussion of the testing performed at the GLEF can be found in the Geothermal Fluid Chemistry section of this document.

1.4 Heber Binary Demonstration Plant

In 1980, DOE entered into an agreement with SDG&E to share the cost with EPRI and others of constructing a 45-MW_{net} binary power plant near Heber, California. The purpose would be to demonstrate the ability of binary technology to produce power economically from moderate-temperature hydrothermal resources. At the time, the 45-MW size for the Heber plant was postulated as being the size needed to demonstrate the technology's commercial viability. The plant was designed to use the 180°C (360°F) resource to generate 65 MW of gross output from a binary cycle where a mixed hydrocarbon working fluid (isobutane and isopentane) was vaporized at a supercritical pressure. While this cycle provided a performance advantage relative to subcritical cycles using single component working fluids, to this day the Heber plant remains the only commercial-sized application of a supercritical cycle employing a mixed working fluid.

The Heber plant was designed with two parallel trains of geothermal heat exchangers and two water-cooled, hydrocarbon condensers. The design incorporated four pairs of working fluid pumps in parallel, four brine injection pumps, and two cooling water pumps. The plant had a single turbine and generator set. Figure 6 shows an aerial view of the Heber Binary Demonstration Plant.



Figure 6. Heber Binary Demonstration Plant, California

The Heber plant went online in 1985. Although some of the plant's hydrocarbon pumps experienced problems, the primary issue was the field operator's inability to supply the expected flow to the plant: the plant and field were owned and operated by separate entities. The limited flexibility of the plant's design resulted in greater parasitic loads at reduced flow rates, reducing net output. The use of a single turbine generator contributed to this lack of operation flexibility and limited output. Design turbine inlet conditions could not be met due to the reduced brine flow, adversely affecting turbine efficiency. The temperature limit, which was imposed to prevent silica precipitation, required additional throttling of the working fluid flow and consequently contributed to keeping the power output low.

Subsequently, the Heber plant production capacity was expanded and had a design brine flow rate of 7.65 million pounds per hour (lb/h). By 1987, flow rates reached up to 4.9 million lb/h, producing a maximum plant output of 36 MW (gross) and 21 MW (net).²⁵ In the late 1980s, plant operation was suspended due to the inability of the plant and field operators to resolve issues related to the adequacy of geothermal fluid supply.

Because the maximum geothermal fluid flow supplied to the plant was only about 65 percent of the design value in the first two years of plant operation, the performance of the working fluid system components and supercritical cycle with the mixed working fluid could not be fairly assessed. The properties were subsequently sold to Ormat Technologies, Inc., which expanded the field and built a binary plant immediately adjacent to the 45-MW plant.

1.5 Pleasant Bayou—Hybrid Geo-pressured Geothermal Power Plant

In 1989, DOE and EPRI co-funded the demonstration of a hybrid power concept using the geopressured geothermal resource at DOE's Pleasant Bayou test facility in Texas. Ben Holt Company designed the plant. Eaton Operating Company, Inc. and the Gas Research Institute (now called the Institute of Gas Technology [IGT]) built and operated it.

In a typical hybrid conversion system, electricity is generated from a geopressured resource by using the thermal and hydraulic energy in the co-produced high-pressure, high-temperature brine as well as from the methane dissolved in the brine. A simplified schematic of the flow diagram for a hybrid plant is shown in Figure 7.

The high-pressure fluid at the well head is expanded through a pressure reduction turbine that drives an electrical generator. As fluid pressure drops, the methane gas in the brine comes out of the solution. The gas is separated from the brine and either sold as natural gas or burned in a gas engine to produce electrical power. The hot, liquid brine leaving the gas separator is used in a conventional geothermal binary cycle plant to preheat and vaporize the binary working fluid before being injected. In this hybrid cycle, the exhaust gas from the gas engine vaporizes a portion of the working fluid flow.

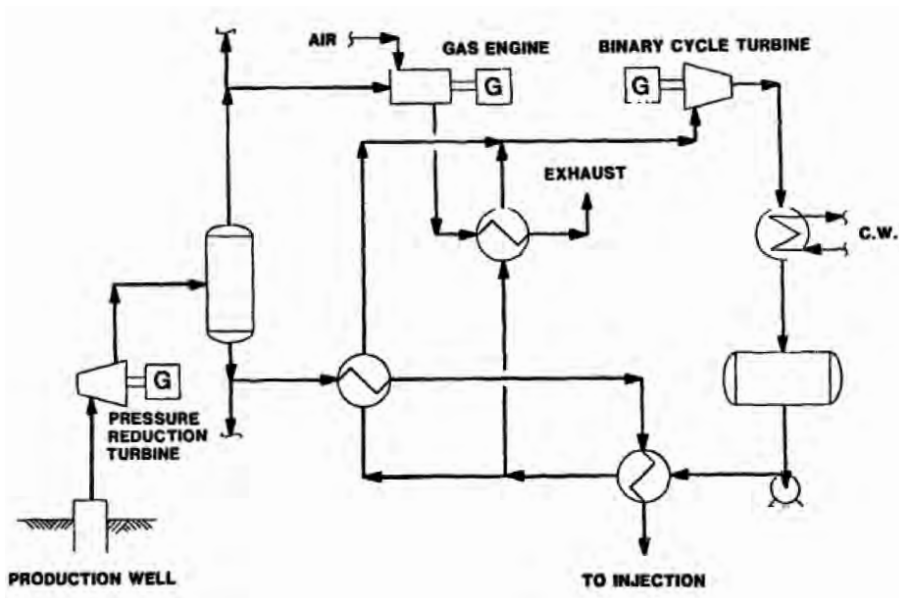


Figure 7. Geopressured-geothermal hybrid cycle

With the exception of the pressure reduction turbine, this typical hybrid system was installed at Pleasant Bayou.²⁶ However, valves were used in lieu of a turbine to reduce fluid pressure. The plant produced about 1 MW of power from 10,000 barrels per day of 143°C (290°F) brine that contained 22 standard cubic feet (scf) of gas per barrel of brine. The gas engine generated a little more than half of the total power; the binary cycle turbine generated the rest.

Prior to the plant's installation at Pleasant Bayou, testing was conducted to develop scale inhibitors for the well's brine, which had a high potential for scaling. Testing showed that these scaling inhibitors effectively minimized the precipitation of solids on component surfaces exposed to the brines. Corrosion was not an issue, nor were any control issues encountered. The plant operated reliably with availability in excess of 97 percent despite the significant amount of used binary plant equipment which primarily came from the decommissioned 500-kW plant at East Mesa. The Pleasant Bayou plant went online in October 1989 and operated until May 1990 when it was shut down because the injection well required rework.

1.6 Small-Scale Field Verification Projects

Small-scale geothermal power plants are attractive because they can provide distributed power. Industry has shown (e.g., Wendell-Amadee, California and Wabuska, Nevada) that small plants can be used when site-specific characteristics are favorable. Generally, small plants are likely to be more expensive on a per-kilowatt basis compared to larger plants due to economies of scale for plant equipment, and the high fixed costs of exploration and drilling.

An analysis by NREL in 2000 found that, with cost share from the government, a considerable opportunity for small-scale geothermal plants existed in several western states.²⁷ Capital costs could be reduced with field validation of innovative conversion system designs. A solicitation was issued requesting proposals for plants of 300 kW to 1 MW. Contracts were awarded to three projects: Exergy-AmeriCulture, Empire Energy, and Milgro-Newcastle. The Phase I, preliminary design work on all three projects began in 2001. Unfortunately, due to a variety of financial and resource-related reasons, none of these small scale projects went far beyond the initial design phase.

1.7 Findings and Conclusions

Although none of the DOE demonstration power plants or test facilities are operational today, they provided significant contributions to the subsequent development of geothermal energy as a source of electrical power in several specific ways including:

- Access to DOE test facilities allowed research on a variety of geothermal fluid types, and facilitated technology advances in geothermal chemistry and materials, as well as component and power cycle development.
- DOE-supported work, at the GLEF in California, was instrumental in the subsequent development of power production facilities at the Salton Sea.
- The 5-MW plant at Raft River in Idaho was the first to use a multiple-boiling cycle to improve plant performance, validating the benefits of this concept that is now routinely used by industry (as exemplified by Ormat Technologies, Inc.'s cascaded system with binary modules installed in series).
- The prototype plant at Raft River demonstrated the feasibility of un-manned operation of a small binary plant. This concept has been adapted by industry, is extensively used in small binary installations, and is increasingly incorporated into the operations of larger plants.
- The hybrid plant at Pleasant Bayou in Texas was the first to use an energy conversion system that generated power using both the thermal energy and hydrocarbons in fluids produced from a geopressured resource. Though the hybrid system was not commercially viable at the time, there is increasing interest in Texas and elsewhere in using waters that are co-produced with hydrocarbons to generate power.
- Because geothermal fluid flow rates never met design levels, the 45-MW binary demonstration plant at Heber was unable to demonstrate the technical viability and benefit of using mixed hydrocarbon working fluids. The plant, however provided valuable information to the geothermal industry:
 - It caused re-evaluation of what is the viable size of a “commercial” binary plant.
 - It reinforced the need to establish the extent and productivity of a resource before finalizing the power generation facility design.
 - It illustrated the need to provide plant design flexibility in order to accommodate periods of operation when the geothermal fluid is provided at less than optimal design conditions.
 - Ormat Technologies, Inc. achieves this operational flexibility by using multiple modular plants installed in parallel. The company has developed the Heber resource for commercial power generation.
 - The Ben Holt Company air-cooled binary plant design used at Mammoth and Steamboat in California, achieved operational flexibility by using multiple pumps and turbines in parallel. This allowed components to be taken out of service while still producing power.
 - Operational experiences at Heber stressed the importance of having a single entity own and operate the well field and power plant.

2.0

Materials Development

Material selection for geothermal system construction and components is one of the critical first steps in developing a geothermal power plant design. Fluids produced from liquid-dominated resources are hot saline or mineralized fluids that can aggressively attack exposed surfaces resulting in corrosion rates that can lead to premature failures of components or piping, unacceptable O&M costs, and lost revenues due to decreased plant availability. In other words, corrosion can significantly impact power generation costs. While the use of expensive materials, such as titanium, can increase a plant's capital cost, they increase the plant's availability and reduce O&M costs over the lifetime of the plant. If corrosion rates are high, the use of expensive materials can therefore result in lower power generation costs. However, if geothermal fluids are relatively benign, the use of less expensive materials is warranted.

Due to the importance of material selection on the economic viability of power generation, materials studies were a major research area during the early years of federal involvement in developing geothermal energy. Several groups conducted studies at a number of locations, many of which were ERDA/DOE-supported facilities. With the increasing use of geothermal resources for power generation, more cost-effective materials were developed to meet the unique needs of selected applications in some resources.

2.1 Early Materials and Fouling Studies

In early materials research, knowledge of the characteristics of fluids produced from liquid-dominated geothermal resources was limited. Some of the earliest material studies were performed by LLNL at the Salton Sea, involving one of the most chemically aggressive, hyper-saline resources found anywhere in the world. The produced fluids had temperatures up to 225°C (437°F), with total dissolved solid levels approaching 300,000 ppm. Corrosion rates for steel were high (50 to 100 mils per year), as were scaling rates (100 to 160 mils in six months).²⁸ Acceptable materials were limited and expensive. The characteristics of the Salton Sea resource had a significant influence on early materials work.

As other resources were developed and became available, materials R&D work expanded beyond the Salton Sea. In the 1970s, DOE researchers conducted materials testing at Heber, East Mesa, Coso, and The Geysers in California; Raft River in Idaho; and Fenton Hill in New Mexico.

Materials testing at Heber and Raft River supported the binary power plants built at those locations. Pacific Northwest National Laboratory (PNNL) conducted tests to identify fabrication materials for the Heber and East Mesa plants' components and piping systems. PNNL testing identified conditions under which carbon steel's corrosion rates would preclude its use.²⁹ Results suggested carbon steel could not be used for thin-wall applications (i.e., as the tube material in the geothermal heat exchangers). Based upon this material testing, Allegheny Ludlum AL 29-4C[®] Stainless Steel was selected as the tube material for the geothermal heaters in the Heber plant and Trent Tube's Sea Cure[®] as the material for the condenser tubes. The remainder of the Heber plant was constructed primarily using carbon steel.

INL conducted most of the materials testing at Raft River. The temperature of the Raft River resource was lower than that of Heber—140°C (284°F) compared to 182°C (360°F)—with total dissolved solids of less than 3,000 ppm. Testing at Raft River indicated the general corrosion rates for carbon steel were relatively low (up to 3.4 mils per year), but the localized corrosion rates (pitting) with carbon steel were about three to four times higher.³⁰ Due to high pitting rates, admiralty brass was selected as the tubing material for the Raft River heat exchangers. In addition to materials testing, heat exchanger scaling tests were also performed at Raft River.³¹ These tests indicated that the surfaces exposed to the geothermal fluids had lower fouling rates (annual rate < 0.001 btu/h-ft²-°F) than expected, and the design fouling resistance for the geothermal fluid heat exchangers was reduced by half to 0.0015 btu/h-ft²-°F.

Based on the assumption that surface or near-surface water would be available for cooling water make-up, carbon steel was selected for the tubing material in the Raft River's water-cooled condensers. When it was later learned that these waters would not be available, a test program was undertaken to develop methods to treat the plant's effluent geothermal water so that it could be used as the source of make-up water.¹⁵ While methods were developed to minimize fouling in the condenser, testing indicated the corrosion rates for the carbon steel would be excessively high. Subsequent materials testing concluded that the Sea-Cure (A-268-79A), 70-30 Copper-Nickel (B359-B111), and Allegheny Ludlum alloys 6X (A-260) and AL-29-4-C (A-268) would provide substantially improved condenser tube life.³²

The BNL research program examined ways to improve well cements, including the use of polymer concrete and polymer concrete-lined steel pipe for surface equipment. Polymer concrete consists of an aggregate mixed with a monomer, which is then polymerized in place. Steel pipe lined with this material is low in cost and corrosion resistant. BNL researchers focused on identifying the optimal monomer and aggregate composition to provide the desired properties, as well as methods for best achieving the polymerization reaction. In addition to testing with simulated geothermal fluids in laboratory autoclaves, field tests were conducted

at Coso, East Mesa, Heber, Salton Sea, and The Geysers in California; Raft River in Idaho; and Fenton Hill in New Mexico. The polymer concrete was tested at temperatures up to 260°C (500°F) for up to 960 days.³³

Radian Corporation, under a DOE contract, collected data on the performance of various materials exposed to a number of geothermal fluids, including vapor- and liquid-dominated resources in the United States and overseas. U.S. resources studied included Raft River, Idaho; Brady Hot Springs, Nevada; Baca, New Mexico; Klamath Falls, Oregon; Madison Aquifer, South Dakota; and Casa Diablo, East Mesa, Heber, Salton Sea, and The Geysers in California. Using these data, Radian Corporation published guidelines for selecting materials for geothermal power plants factoring in fluid chemistries, material test results, and operating experience for the various resources.⁸

2.2 Material Development Projects

2.2.1 Thermoplastic Coatings—Polyphenylene Sulfide with Additives

As geothermal power plants were built to generate electricity from liquid-dominated resources, the need arose for a low-cost alternative to carbon steel to reduce capital and maintenance costs. This formed the basis for investigations by BNL and NREL to develop coatings for carbon steel tubulars which were resistant to corrosion, erosion, and fouling. BNL developed formulas and conducted laboratory testing and analysis. NREL tested materials in the field at a variety of geothermal resources in cooperation with geothermal power plant owners and operators.

The self-repairing, multifunctional polyphenylene sulfide (PPS) coating system was found to have high resistance to hydrothermal oxidation in geothermal environments with temperatures up to 200°C (392°F). Adding different filler materials enhanced the coating system's surface hardness, thermal conductivity, and mechanical properties.³⁴ Findings suggested that PPS-coated carbon steel components could be used in place of expensive titanium alloys, Inconel™ alloys, and stainless steels in geothermal power plants. The economic advantages of the PPS coating are shown in Figure 8, which illustrates the life cycle costs of four 40-foot-long, 800-tube, brine-working fluid heat exchangers of different materials. The cost of using PPS-coated carbon steel is estimated to be 18 percent of titanium's cost, 20 percent of stainless steel's cost, and 25 percent of uncoated carbon steel's cost.

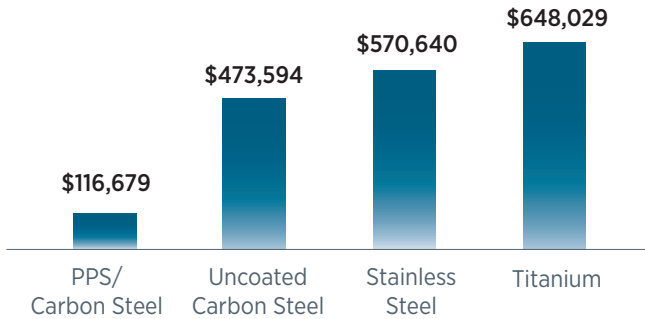


Figure 8. Estimated life cycle costs of brine-working fluid heat exchangers

Through extensive laboratory and field testing by BNL and NREL, PPS-coated carbon steel could be confidently recommended as an alternative to carbon steel. Field testing was carried out under different conditions at various plants. When deficiencies were discovered, fundamental materials science techniques and analyses were used to determine causes and the necessary remediation. The objective was to achieve successful operation at temperatures up to 300°C (572°F) in a variety of brines and applications. The high-performance PPS composite lining system received an “R&D 100 Award” in 2002 and a Federal Laboratory Consortium Award in May 2003. The PPS coating system was commercialized by Curran International and is marketed as CurraLon™.

While most testing was done with coated carbon steel, other metals such as aluminum were also coated and tested. Test specimens came from both BNL and commercial coating shops like Curran International. Testing was performed at the following locations:

- **Mammoth, California:** PPS heat exchanger tubes up to 40 feet in length were tested.
- **Cove Fort, Utah:** PPS-coated steam vent pipe was tested.
- **The Geysers, California:** PPS-lined caustic injection spool was tested at the Aidlin Plant.
- **Puna, Hawaii:** PPS-coated heat exchanger tubes were tested.

Test results were positive.³⁵ In addition to enhancing corrosion protection, the use of PPS increased the ease of cleaning scale from lined heat exchanger tubes resulting in lower maintenance costs. In instances when bonding failures occurred during testing, investigators were able to identify the causes and make the modifications needed to address the problems.

2.2.2 Advanced Coating Materials

Prior to 1997, BNL was involved with studies on coatings with a specific focus on technical needs at The Geysers geothermal field. Corrosion problems had contributed to a decrease in power generation and an increase in operating costs. BNL, in cost-shared work with geothermal steam producers, researched the following materials needs:

- Erosion and cavitation-resistant liners for steam transmission piping.
- Stress corrosion resistant materials for turbine components.
- Low cost corrosion resistant coatings for dry cooling tower applications.
- Corrosion resistant coatings for vent gas blowers.

From 1998 to 2006, a key objective of BNL's R&D work was to develop advanced coating material systems that could better prevent corrosion, erosion, and fouling, and thus extend the lifetime of carbon steel plant components that operated in harsh environments. Components that could benefit included heat exchangers and heat exchanger tubes, sheet or pipe and pipe joint areas, well heads, condensers, and steam separators. Because these plant components operated in chemically, physically, and thermally different environments, the material criteria of developing the coating systems depended on the particular component.

DOE also supported research that built on prior work to discover the next generation of coating materials that have greater benefits than PPS. Research covered nano-composite coatings, coatings for air-cooled condensers, coatings for separators, and heat exchanger tube joints.

NANO-COMPOSITE COATINGS

BNL's effort to develop new coating materials focused on the polyetheretherketon (PEEK)-clay nano-composite that has better thermal stability (> 300°C [572°F]) than PPS. Efforts concentrated on developing the montmorillonite (MMT) clay-polymer nano-composite technology, which further raises the softening temperature and hydrothermal stability of PEEK and PPS. BNL developed a new chemical treatment technology that made it possible to produce functional nano-scale MMT fillers and to disperse them uniformly in the polymer matrix.³⁶ Preliminary testing exposing the MMT-PEEK and MMT-PPS coatings to 300°C (572°F) brine in an autoclave was successful.

COATINGS FOR AIR-COOLED CONDENSERS

With increased electricity demand in the summer, an important issue is a geothermal binary plant's net monthly energy delivery which is reduced by up to 30 percent during the summer as compared to the winter. A simple way to address this problem is to spray cooled geothermal brine over the

surfaces of the aluminum-finned, steel tubing condenser. While this method is easy, spraying the brine increases the likelihood of corroding the condenser's components as well as depositing geothermal brine-induced mineral scales. Anti-corrosion and anti-fouling coatings are needed to deal with this issue.

To design coatings that met its material criteria, BNL developed a new technology of self-assembly nano-synthesis that allowed a nano-composite structure consisting of the nano-scale rare-earth metal oxides as the corrosion inhibitors, and water-based organometallic polymers (OMP) as the hydrophobic matrix.³⁷ Among the rare-earth metal oxides, environmentally benign cerium (Ce) oxide was employed in this nano-composite system. Using this synthesis technology involving three spontaneous reactions, condensation, amidation, and acetoxylation, between the Ce acetate dopant and aminopropylsilane triol (APST) as the film-forming precursor aqueous solution, a synthetic OMP material was composed of Ce oxide as the nano-scale filler and poly-acetamide-acetoxy methyl-propylsiloxane (PAAMPA) polymer in a family of OMP. This nano-composite coating extended the useful lifetime of steel exposed in a salt-fog chamber at 35°C (95°F) from only about 10 hours to about 768 hours. Furthermore, this coating protected an aluminum substrate from corrosion far better than it did one of steel. The salt-spray resistance of film-covered aluminum panels was strikingly extended to more than 1,440 hours compared with roughly 40 hours for bare aluminum.

Following the development of the OMP coating and its method of application, NREL conducted field tests of OMP-coated aluminum-finned tubing under an extremely harsh environment, exemplified by a field fatigue test of 24,500 cycles of brine wet then dry conditions each cycle. Accelerated exposure tests were conducted at the Mammoth Pacific Geothermal, LP binary facilities in California. Initial results indicated the 2.2 µm coating thickness did not provide adequate corrosion protection. Program resources did not allow for testing with thicker OMP coatings.

COATINGS FOR STEAM SEPARATORS

The steam separator plays a pivotal role in minimizing the extent of erosion of the turbine blades caused by brine-laden steam containing hard mineral solids impinging on the blade surfaces. Consequently, the metal components of separators must exhibit excellent resistance to corrosion and abrasive wear at hydrothermal temperatures up to 210°C (410°F). BNL worked in collaboration with Two-Phase Engineering & Research, Inc. to develop and evaluate less costly materials as internal coatings for carbon steel separators. Researchers also worked to develop coatings for steam separators for use with higher temperature resources. Higher temperature resources can require expensive materials such as the Inconel™ 625 nickel-chromium (Ni-Cr) alloy, when aggressive brines are encountered. Carbon steel vessels coated with cost-effective, high-temperature stable, anti-corrosion, and anti-fouling materials could significantly reduce component and plant costs.

HEAT EXCHANGER TUBE JOINTS

The application of coatings to tube surfaces in commercial heat exchangers requires that methods be developed to join the coated tube to the heat exchanger tube sheet. Utilizing the common rolled and welded tube joints with pre-coated tubes often damages the coatings and lead to rapid failures of the underlying carbon steel tubes. Efforts were focused on the application of coatings after the tube-to-tube sheet joint has been made. BNL tested a newly developed solvent-dissolvable polyarylethersulfone (PES) polymer provided by Solvay Advanced Polymers, L.L.C. While autoclave validation testing was limited, the PES coating adequately protected the jointed steel against corrosion in 200°C (392°F) brine.

2.2.3 Thermal Spray Coatings for Piping Surfaces

INL researchers examined applying thermal spray coatings to the surfaces of exposed steel (or other commonly used alloys) to provide corrosion and scaling protection in extreme operating environments. The coating material was a metal alloy selected to provide the required protection for a specific application or fluid chemistry. Research focused on earlier technology advancements that would allow these coatings to be applied to the internal surfaces of piping typically found in commercial geothermal plants.³⁸ Field tests were done at CalEnergy Generation's Salton Sea facilities. Limited tests were also conducted at one of Calpine Corporation's facilities at The Geysers.

Initial tests were conducted at the Salton Sea with thermal spray coated carbon steel coupons.³⁹ This was followed by testing coated sections of steel piping installed between a production well and the power plant. Piping sections were removed and the coating integrity was evaluated after nine months of operation. Evaluation showed that the coating was at a relative 100 percent thickness over half of the total pipe surface area. Though some decrease in the coating thickness had occurred along the bottom of the pipe and in areas of increased turbulence, the coating was intact, providing corrosion protection after nine months of service. This work was done in collaboration with industry partner, Zatorski Coating Company, Inc., and the geothermal facility operators.

2.3 Findings and Conclusions

Materials development was a primary focus of the early stages of DOE-supported energy conversion R&D and remained critical throughout the life of the program. Key findings and conclusions include:

- Early investigations provided a wealth of information regarding fluid chemistries, corrosion rates, fouling rates, and material compatibilities. This information was documented in Radian’s “Material Selection Guidelines for Geothermal Energy Utilization Systems.”⁸ While material testing should always be done to confirm the compatibility of candidate materials with fluids from a specific resource, this important, early work provided the basis of knowledge for identifying those candidate materials.
- As materials investigations expanded beyond the Salton Sea’s hot, hyper-saline brines, testing showed that for more benign, lower temperature resources, carbon steel was adequate for all plant components, including the thin-walled tubes in the geothermal heat exchangers in certain instances. Using carbon steel in lieu of stainless steel can reduce a plant’s total capital costs by up to 10 percent. Subsequent commercial binary power plants predominantly use carbon steel for all piping and components, including the heat exchanger tubing.
- Despite carbon steel’s widespread use, industry needed a low-cost alternative that could extend equipment life and be used with higher temperature, more corrosive fluids. Research consequently focused on coating carbon steel components to provide corrosion protection. PPS, a coating developed at BNL, was shown in numerous field tests to provide corrosion protection for lower temperature hydrothermal resources (< 200°C [392°F]).

3.0

Geothermal Fluid Chemistry

Geothermal fluids are waters that are heated at depth either by the earth's natural geothermal gradient or by cooling of magmas injected in the upper crust from great depth. Sources of this water vary, as do the final compositions of the heated fluids (which can have a pH of 5 to 9) and salinities ranging from 1,000 to 300,000 ppm TDS. Both chemistry and temperature dictate the geothermal fluid's corrosion and scaling potential, which in turn influences capital (material selection) and O&M costs. Higher temperature resources, with higher enthalpy content, are desired for power conversion but mineral solubilities generally increase with temperature. As a consequence, hotter fluids tend to have higher levels of dissolved solids and often carry dissolved gases as well, increasing their corrosion and scaling potential.

DOE energy conversion R&D focused on improving the understanding of geothermal fluid chemistry—particularly the formation and control of silica scale. A good deal of this work was done early in the program by investigators at the Salton Sea. More recently, efforts examined mineral recovery from geothermal fluids, creating an additional income stream for a geothermal power plant and improving the economics of power generation.

3.1 Geothermal Chemistry Projects

3.1.1 Silica Scale Inhibition

Geothermal fluids often originate in subsurface fracture systems in quartz-bearing rocks. The solubility of quartz (SiO_2) in water generally relates directly to temperature (i.e., higher temperature fluids contain more dissolved quartz and have higher potential for silica scaling as energy is extracted and the fluid cools). Silica scaling problems in geothermal applications range from moderate to so severe that the power generation process must be specially designed to limit scaling. Variation in fluid chemistry and plant conditions at different geothermal fields complicate the selection of effective inhibitors.

Initial interest in controlling silica formation began in the early 1970s with efforts to develop the Salton Sea geothermal resource. Rapid corrosion of common metal alloys, along with the high rate of silica scaling (up to 1 millimeter [mm] per day),

were the two major problems that needed to be solved before power generation could be commercialized from the resource. Efforts to develop the Salton Sea resource led to the construction of the GLEF as a cooperative effort between SDG&E and ERDA/DOE. In 1975, LLNL began studies of brine chemistry and materials at the GLEF. Their testing showed that adding hydrochloric acid to the brine lowered scaling rates and the formation of suspended solids in the brine.⁴⁰ Significant retardation was found with only a slight reduction in brine pH (from 5.5 to 5.0); virtually complete inhibition could be achieved at a pH of about 3.

In 1978, DOE issued an industry solicitation seeking scale-control agents for the Salton Sea's primarily silica scales. In subsequent field tests, none of the proprietary additives reduced the rate of scale formation or retarded silica precipitation. Approximately 120 different organic compounds of various types were screened to determine their influence on silica in the hyper-saline geothermal brine. The most promising compounds were subjected to scaling tests during which corrosion measurements were performed.⁴¹ These studies confirmed that brine acidification was by far the most effective chemical method of brine stabilization and scale control. While brine acidification increased metallic corrosion rates, this could be mitigated by proper materials selection.

Testing by LLNL showed that seeding with previously precipitated silica reduced the downstream level of silica supersaturation and retarded scale formation in straight runs of pipe. It was concluded that this method of scale control had promise if brine handling equipment could tolerate the high levels of suspended solids. In 1979, pilot studies were conducted at the GLEF for the Magma Power Company. These studies investigated the use of a flash crystallizer system that was seeded to deliberately precipitate silica. This technique was shown to be a promising basis for designing a power plant to use the Salton Sea fluids. The technique became known as the Crystallizer Reactor Clarifier (CRC) Process. In conjunction with brine acidification, CRC provided brine handling capability that was used in the commercial development of the Salton Sea resource.⁴²

3.1.2 High-temperature, High-salinity Geothermal Fluids

LLNL's energy conversion R&D focused on better understanding the chemistries of geothermal fluids, as well as on component and materials development.

STUDIES OF THE DISSOLUTION OF GEOTHERMAL SCALE

Laboratory tests were performed on samples from the GLEF to examine the ability of several low-cost mixtures of reagents to chemically remove scale from process systems.⁴³ Predominantly silica scales were partially dissolved by hot sodium hydroxide (NaOH) and a solution of NaOH and iron chelate Dow RT2 (EDTA). The best reagent for dissolving the phosphate buffered saline (PbS)-rich, high-temperature scale was nitric acid (HNO₃) with hydrogen fluoride (HF) at

80°C (176°F). More concentrated solutions, particularly of compounds such as HF, were more effective but hazardous to use. A combination of chemical and mechanical cleaning methods was judged the most effective way to remove scale.⁴⁰

CHEMICAL MODELING OF GEOTHERMAL SYSTEMS

Various chemical reaction numerical models⁴⁴⁻⁴⁶ were developed in support of the R&D activities to better understand geothermal fluid chemistries, including:

- A model was developed that utilized the Helgeson-Herrick geochemical code to predict precipitation in brines at the Salton Sea Geothermal Field.
- A predictive model was developed to calculate equilibria between liquid and volatile components of two-phase fluids.
- Codes were developed for calculating the thermodynamic physical properties of geothermal brine and steam mixtures.

PROCESSING GEOTHERMAL BRINE EFFLUENTS FOR INJECTION

LLNL developed a process for treating Salton Sea brine effluents for injection. The process consisted of solids contact clarification in which the spent brine is first intimately contacted with sludge solids and then passed through a dense sludge blanket of silica-rich precipitated solids.⁴⁷ The clarifier overflow stream is then polished by sand or pre-coat pressure filtration. Bench scale tests indicated an anionic coagulant aided enhanced clarifier performance. A pilot-sized reactor clarifier using brine effluents from the GLEF demonstrated that it would be feasible to produce chemically stable brine effluents, with 1-2 ppm levels of suspended solids suitable for subsurface injection without impairing injection wells.

Suitability for injection was determined by measuring the flow of both untreated and treated brine through media that simulated subsurface injection formations. Untreated effluent brines had very high suspended solids levels. Injection was not feasible unless particulates 1µm and larger were removed. Brines with pH lowered to retard scale formation had markedly lower suspended solids levels. At a pH of approximately 4.5, however, this brine still was not highly injectable without pre-filtration by the clarifier-filtration system.

Surface waters at Salton Sea and the New and Alamo Rivers were evaluated as potential make-up waters during injection.⁴⁸ Direct injection of these waters was not feasible, however, because of their high suspended solids levels and because mixing with geothermal brine effluent resulted in additional precipitation.

HYDROGEN SULFIDE ABATEMENT USING GEOTHERMAL BRINE EFFLUENTS

A simple and potentially inexpensive way to remove hydrogen sulfide (H₂S) from NCGs resulting from the geothermal flash process was field tested in the mid-1970s. The method consisted of scrubbing the NCGs containing H₂S

with brine effluents containing relatively high concentrations of lead (Pb), iron (Fe), and zinc (Zn).⁴⁹ For plant applications, NCGs including H₂S were removed from a surface steam condenser and scrubbed with effluent brine just prior to pre-injection clarification. The precipitated metal sulfides were removed in the clarification process. The remaining NCGs were vented.

3.1.3 Chemistry Instrumentation Development

The ability to monitor fluid conditions in real-time with in situ instrumentation improves the ability to mitigate corrosion and scaling. PNNL worked on developing such instrumentation for geothermal fluids by testing commercially available, in-line chemical monitoring instrumentation in hot geothermal brines.⁵⁰ PNNL found that available instruments were generally unable to withstand the pressures, temperatures, and salinity of geothermal fluids. Addressing such deficiencies, PNNL developed an electrode-less conductivity probe and oxidation-reduction cell suitable for geothermal use. Efforts to develop an in situ, high-temperature pH probe were unsuccessful. INL's work on monitoring instrumentation is covered in Section 5.1.1 (Plant Process Steam Monitors).

3.1.4 Fluid Sampling and Analysis

The chemical analysis of geothermal fluids typically requires that the samples collected be cooled and depressurized. The sampling process, as well as cooling and depressurization, however, can alter fluid chemistry. In order to understand these effects and to provide for replicability and reliability in the analysis process, PNNL developed methods and protocols for sampling and analyzing single phase (liquid or vapor) fluids in surface piping or components. The protocols developed were field tested at East Mesa in California's Imperial Valley, and the results were compared to those under controlled laboratory conditions. The resulting preferred sampling techniques and analysis methods were published and made available to industry.⁵¹

3.2 Treatment of Geothermal Brines

High-salinity brines like those found at the Salton Sea can produce precipitates composed of a mixture of toxic and valuable metals. Such residues may be considered mixed wastes and subject to regulatory requirements. BNL's work to treat these brines began in 1988. In response to research results and industry input, BNL's R&D efforts had three main objectives:

1. To develop biochemical processes that address environmental concerns associated with the disposal of geothermal brines and precipitates (scales and sludges).
2. To create processes that produce commercially attractive silica products from brines.
3. To demonstrate silica recovery on a pilot scale.

BNL researchers focused on developing cost-efficient and environmentally acceptable means of removing toxic metals from geothermal brines and their precipitates, enabling their reinjection and disposal as nonhazardous solid waste.⁵² Efforts focused on developing biochemical processes that could remove more than 80 percent of toxic metals in less than 24 hours. The processes could be modified to remove specific metals such as arsenic (As) and mercury (Hg), or valuable metals such as chromium (Cr), gold (Au), and silver (Ag).

Figure 9 illustrates an example of a biochemical process developed by BNL based on treating a highly saline geothermal sludge from a 50-MW plant. The process converts 93 percent of the sludge from regulated to non-regulated waste. In later work, the process was simplified and customized for specific geothermal sites.⁵³

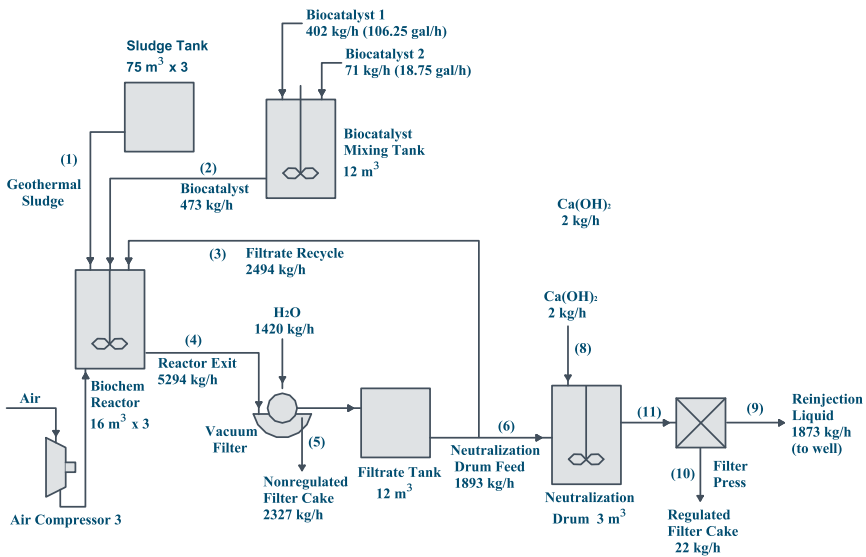


Figure 9. Process for converting geothermal sludge from regulated to non-regulated waste

3.3 Recovery of Minerals and Metals from Geothermal Brines

Researchers at BNL and LLNL examined the feasibility of extracting minerals and metals from geothermal brines. As they flow through layers of the earth's crust, geothermal waters dissolve minerals and metals. Mineral and metal recovery from geothermal brines can be viewed as adoption of "solution mining by nature" followed by isolation and purification by applying hydrometallurgical techniques. Offsetting power production costs by co-producing value-added products was the motivation behind research into mineral and metal recovery from geothermal brines.

Optimally, mineral extraction occurs near or after energy extraction ends. The solubilities of the dissolved constituents decrease at lower fluid temperatures, facilitating their removal. In addition, removing dissolved solids after energy extraction minimizes downstream scaling, allows for the extraction of additional energy from the fluid, improves plant performance, and facilitates injection of spent fluids. Recovery of valuable materials is dependent on the state and chemistry of the feedstock (i.e., the cooled geothermal fluid or solid material such as sludge or scale that precipitated from the geothermal fluid).

3.3.1 Recovery techniques

SOLIDS

The recovery of minerals and metals from solid geothermal residues, such as sludge and scale, can be accomplished using acid or biochemical leaching. At the Salton Sea, solid waste from the clarifier contains a mixture of iron-bearing silica, salts, and other heavy metals. Hydrochloric acid can be used to leach out iron and other metals. The remaining silica becomes pure enough for use as a pozzolanic additive for cements.

FLUIDS

The recovery of minerals and metals from geothermal fluids can be accomplished by sorption (absorption and adsorption taking place simultaneously), evaporation, or precipitation as sulfides as explained in the following examples.

- Synthetic ion-exchange resins, as well as bacteria, are known to adsorb ions selectively from solution. The selectivity and capacity of the adsorption are dependent upon pH, temperature, and ionic strength. Separation using commercial ion-exchange resins has been used to recover zinc from high salinity brines. Laboratory studies reported a process through which the adsorptive property of biological cell walls was used to recover uranium (U), cobalt, (Co), zinc (Zn), manganese (Mn), and lithium (Li) ions in solution. This process has not been commercialized.
- In the early 1970s, solar evaporation ponds were used to recover salt minerals from saline brines in the Imperial Valley. Evaporation is an energy-intensive process with limited application for mineral recovery from geothermal fluids, especially if injection is required to sustain resource productivity.
- Adding hydrogen sulfide to the geothermal fluid precipitates out most heavy metals as insoluble metal sulfides, and was shown to be technically viable during testing at the GLEF. The advantage of this treatment is its near-quantitative efficiency. However, if the geothermal brine is rich in many metals, the quantitative precipitation gives rise to a complex metal sulfide mixture that requires further purification.

3.3.2 Targeted Minerals

Efforts to recover minerals or metals from geothermal fluids targeted specific chemical species contained in the fluids.

SILICA RECOVERY

Silica exists as a dissolved species in most liquid geothermal resources. The concentration of silica varies, and is dependent upon the geologic setting of the resource, the chemical nature of the brine, and the pressure and temperature of the reservoir system. Higher silica concentration is attractive in terms of silica recovery per volume of brine processed. In addition, silica must be removed or reduced in concentration before other components can be extracted from geothermal brines.

Silica is a versatile material whose price varies widely depending on its purity and properties. Several industrial applications of precipitated silica have been identified. The commercial market for silica is about six million pounds per day; the total amount produced by the world's geothermal plants is about three million pounds per day. Wholesale prices for silica range from a few cents per pound for cement additives and desiccants, to around one dollar per pound for silica used as rubber and paper additives. A high-priced silica market exists for ultrapure, uniform textured silica for chromatography but is small relative to the large amount of silica geothermal plants produce.

Many methods have been used to precipitate silica from geothermal fluids. One technique is to add salts such as magnesium chloride whose cations increase polymerization rates and facilitate agglomeration of silica. Synthetic polymer electrolytes can also be used but are more costly. Although silica solubility in geothermal fluids does not vary significantly at pH values less than about 8, the rate of silica polymerization does increase with increasing pH. By adding a base, the rate of silica polymerization increases and leads to the formation of silica colloids, which then flocculate to form silica precipitates. Cooling geothermal brine increases the degree of silica supersaturation, leading to nucleation of silica colloids. Seed silica can be added to geothermal brines to act as nucleation sites for silica precipitation.

The key to making saleable silica from geothermal plants is to match the compositional and textural requirements of the specific targeted market. If geothermally derived silica does not meet the market's compositional requirements, it may be acid-leached to remove unwanted contaminants. Textural requirements are the most difficult to match yet the most important.

RECOVERY OF LITHIUM AND ALKALI METALS

Lithium is often enriched in geothermal fluids. In the early 2000s, the market for lithium was estimated at half a billion dollars per year. Lithium is used in the production of ceramics, glass, and aluminum, and increasingly in rechargeable batteries. Lithium can be extracted from geothermal fluids by

direct precipitation as lithium carbonate, or it can be captured using ion-exchange resins. Both methods are currently used for commercial lithium extraction from non-geothermal brines. Although the U.S. market for cesium and rubidium is a few thousand kilograms per year, both elements can be enriched in geothermal fluids and extracted at a profit due to their high values.

OTHER BYPRODUCTS

Geothermal fluids may be used to produce inexpensive salts, such as sodium chloride (NaCl), sodium sulfate ($\text{Na}_2\text{SO}_4 \cdot \text{H}_2\text{O}$), and calcium chloride (CaCl_2). While not valuable themselves, such salts may be the byproducts in the recovery process of other more valuable solids. They may also add to the profitability of geothermal co-production.

In addition, precious metals including gold and silver tend to be enriched in geothermal scale. Extraction from the scale rather than the fluid has been attempted. After successful pilot plant studies, CalEnergy Operating Company developed a commercial zinc extraction process at the Salton Sea. Efforts to “scale up” the zinc recovery process did not prove economically viable at the time and the extraction plant was subsequently shut down.

3.3.3 Field Testing

DOE’s mineral extraction R&D included field testing various mineral recovery techniques at several operating geothermal facilities.

SILICA EXTRACTION AT DIXIE VALLEY AND STEAMBOAT SPRINGS, NEVADA AND COSO, CALIFORNIA

BNL investigated developing economic and environmentally acceptable methods for extracting silica from fluids at three geothermal sites. At the time, these sites were owned by Caithness Operating Company—Caithness Dixie Valley, LLC; Yankee-Caithness Steamboat Spring; and Coso Operating Company. Research found that silica derived from low-salinity geothermal resources can directly compete in terms of quality with higher priced silica used by industrial chromatography separation industries.

In BNL’s research,⁵⁴⁻⁵⁵ a portion of the brine from the injection system was flashed to atmospheric pressure to concentrate the silica. (The estimated concentration was 450 ppm.) Silica was precipitated from the un-flashed brine by adding magnesium chloride. The separation of silica was achieved in a two-step process. A batch load was allowed until gravity settling of the silica occurred. The clear supernatant brine was removed by siphoning, leaving a small amount of brine with concentrated silica precipitate. The silica was removed from this concentrated solution by gravity filtration. The volumetric ratio of the fluid taken from the injection stream to final silica concentrate was 1,200:1.

SILICA EXTRACTION AT MAMMOTH LAKES, CALIFORNIA

Work to extract silica from brines at the Mammoth Lakes, California geothermal plant was performed with R&D sponsorship by DOE through LLNL, the California Energy Commission (CEC), and Mammoth Pacific Geothermal, LP. Mammoth's geothermal fluid has a low salinity (1,200 ppm TDS), with very low calcium and negligible iron and other metals content. The co-produced silica is consequently very pure and could be marketed for high-purity applications such as colloidal silica for silicon chip polishing.

Silica extraction at Mammoth was complicated by the relatively low silica content of 250 milligrams per liter (mg/L). To provide the higher silica concentrations needed for efficient silica extraction, the geothermal fluid was processed through a reverse osmosis (RO) membrane to produce a silica-enriched concentrate that could be used for extracting silica and other metals.⁵⁶ The low TDS permeate produced by RO was then used to augment the plant's heat rejection system. Silica was precipitated from the concentrate using a commercial agglomerating agent, and removed using a tangential flow ultrafilter. The silica was then characterized and analyzed, and samples were sent to commercial laboratories for real product testing (e.g., as a rubber binder for tires). Comparing test results with the properties of known commercial silica-guided extraction aimed for a specific use.

3.4 Findings and Conclusions

An early goal of DOE energy conversion research was to increase the knowledge of geothermal fluid chemistry, in particular to understand the precipitation of dissolved solids in saline fluids and develop methods for using those fluids to generate electrical power.

- One of the more significant contributions made to the geothermal industry by the DOE program was developing the technologies needed to utilize Salton Sea's hyper-saline geothermal fluids. DOE-supported research developed brine acidification and reactor-clarifier technologies. These are incorporated in power plants that currently produce about 335 MW of electricity from the Salton Sea resource.⁵⁷ This level of power production would likely not have been attained without DOE's support of the initial research performed at the Salton Sea.
- Geothermal chemistry R&D also looked at integrating mineral recovery with energy extraction, improving the economics of geothermal operations. Researchers examined and successfully tested several techniques to remove silica from geothermal fluids.

- Much of DOE-supported geothermal chemistry research was the result of cooperation between DOE researchers and industry, including early work performed at the Salton Sea in which SDG&E and Magma Power Company participated in construction and testing at the GLEF. Subsequently, Caithness Operating Company and Mammoth Pacific Geothermal, LP supported mineral recovery testing activities by DOE researchers.

4.0

Power Plant Design and Engineering

DOE-supported research to lower power generation costs included work to develop innovative plant components and more efficient power cycles. Early research emphasized developing technologies and components necessary for power production from corrosive geothermal fluids with high scaling and fouling potentials. More recently, DOE research sought to enhance component performance to increase plant output and lower power generation costs.

In the early 1980s, DOE began focusing on developing binary cycle technologies to increase the viability of producing power from lower temperature liquid-dominated resources. The increased attention given to these resources was partially in response to USGS assessments of the geothermal resources of the United States.³⁻⁴ These assessments found that lower temperature geothermal resources were more prevalent across the country than higher temperature resources.

4.1 Component Development Projects

4.1.1 Innovative Heat Exchangers

Researchers designed new heat exchangers to use in binary power cycles with aggressive geothermal fluids having significant potential for corrosion and scaling. Using expensive materials and alloys as the tube material in conventional shell and tube heat exchangers resolved the corrosion issue. However, it did not necessarily resolve the scaling issue. If scaling is excessive, larger heat exchangers are needed, adding to capital and O&M costs.

DIRECT CONTACT HEAT EXCHANGERS

Development of a DCHX was pursued to extract heat from the geothermal fluid without the brine coming in contact with thin-wall tubing surfaces. In a DCHX, the working fluid is dispersed into the geothermal fluid flow as droplets that are heated and eventually vaporized. Both the geothermal and working fluids are present in the streams leaving the heat exchangers. Minimizing the effects of the “other” fluids in both the effluent brine and working fluid streams was integral to the development of these heat exchangers. Figure 10 is a schematic of a spray column DCHX.

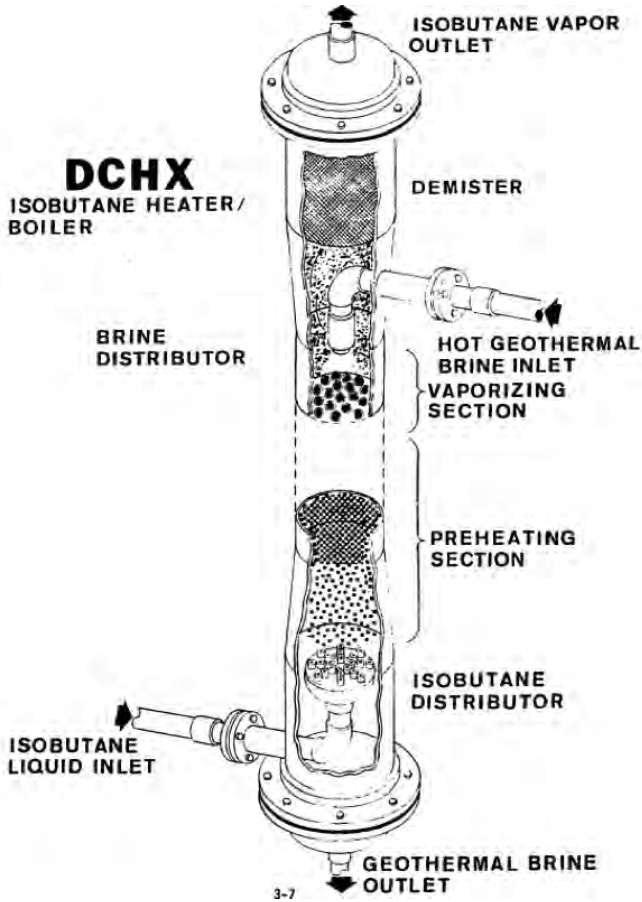


Figure 10. Schematic of spray column direct contact pre-heater boiler

DOE supported research to establish the thermal and hydraulic performance of a DCHX to determine whether it could be used in binary cycles with higher salinity fluids. Early DCHX investigations included work by Ben Holt Company, DSS Engineers, Occidental Research, and the University of Utah. The Ben Holt Company conducted laboratory studies of heat transfer between hexane and hot water in a direct contact exchanger.⁵⁸ The exchanger was tested as a spray column as well as with sieve-trays, disk-and-doughnut trays, and two types of packing. Solubility measurements were performed and system studies conducted to assess the impact on cost and performance. Occidental Research examined the performance of a near-critical pressure DCHX using an isobutane working fluid,⁵⁹ and field tested a DCHX operating at both subcritical and supercritical pressures at East Mesa, California.

Under subcontract to LBNL, DSS Engineers focused on using a spray column operating at a subcritical pressure where preheating and boiling were accomplished in the same heat exchanger. The spray column was field tested at the East Mesa facility from 1977 to 1979.⁶⁰ Initial testing was conducted with an isobutane working fluid; isopentane was used in later tests. A direct contact condenser was tested as part of these investigations. It was found that, while the direct contact condenser's thermal performance was good, difficulties existed in separating the geothermal and working fluids and the loss of isopentane in the cooling water was unacceptable. During field testing at East Mesa, the DSS test unit was modified to test a Barber-Nichols Inc. binary turbine—the first power produced from a binary plant in the United States.

The University of Utah began investigating direct contact heat exchangers in binary cycle applications in 1974. These investigations were the most extensive funded by ERDA/DOE to develop direct contact heat exchangers. They continued until the mid-1980s and included analytical evaluations of the theoretical performance of heat exchangers, cycle performance, and cost studies.⁶¹⁻⁶³ Different types of exchangers were also tested. Early efforts focused on developing a direct contact boiler that was tested at the University of Utah and Raft River in Idaho. Subsequent investigations tested a direct contact condenser and tested and evaluated spray and sieve-tray columns for liquid-liquid preheating.

Investigations at East Mesa by Barber-Nichols and Raft River by INL incorporated larger DCHXs into small power plant operation. These plants were designed to minimize the effects of water and NCGs in the working fluid vapor and the working fluid in the cooled brine. The spray tower tested by Barber-Nichols achieved pinch points of 0.6°C to 2.1°C (1.1°F to 3.7°F) using an isobutane working fluid.²⁰ (The pinch point, or minimum approach temperature, is the minimum temperature difference between fluids during a heat exchange process.) At Raft River, a sieve-tray column was tested using isobutane-propane, isobutane-hexane, and propane-isopentane mixtures. The heat exchanger achieved a pinch point temperature of less than 0.3°C (0.5°F) with pure fluids.¹⁵

FLUIDIZED BED HEAT EXCHANGER

In a fluidized bed heat exchanger, geothermal brine “fluidizes” or suspends a bed of sand or other material in contact with the heat exchange tube surface. Movement of this fluidized bed caused by the geothermal flow reduces scaling potential on the tubes both by “scrubbing” the surface of the tube wall and by providing a nucleation site for mineral precipitation to occur. Reduced fouling of the tube surfaces increases the overall heat transfer coefficients and results in smaller heat exchangers. Minimizing scale formation on surfaces also reduces localized corrosion processes.

Researchers at INL and Aerojet Liquid Rocket Company developed fluidized bed heat exchangers for binary geothermal applications. INL focused on a design in which the geothermal fluid and bed material were on the shell side of the heat exchanger.⁶⁴⁻⁶⁵ A schematic of INL's fluidized bed heat exchanger is shown in Figure 11. The fluidized bed is located between the distribution plate and the disengagement plate on the shell side of the exchanger. Aerojet used an approach in which the geothermal fluid and bed material circulated through the inside of the tubes.⁶⁶ Field testing performed at Raft River in Idaho and the GTF in California's Imperial Valley examined several variables including the velocities and flow distribution system required to adequately fluidize the sand bed, the different types of bed material, the scaling and erosion of surfaces exposed to the fluidized sand, and the thermal performance of the heat exchanger. Results found that the fluidized bed approach reduced the fouling of tube surfaces exposed to the brine and increased heat transfer rates.

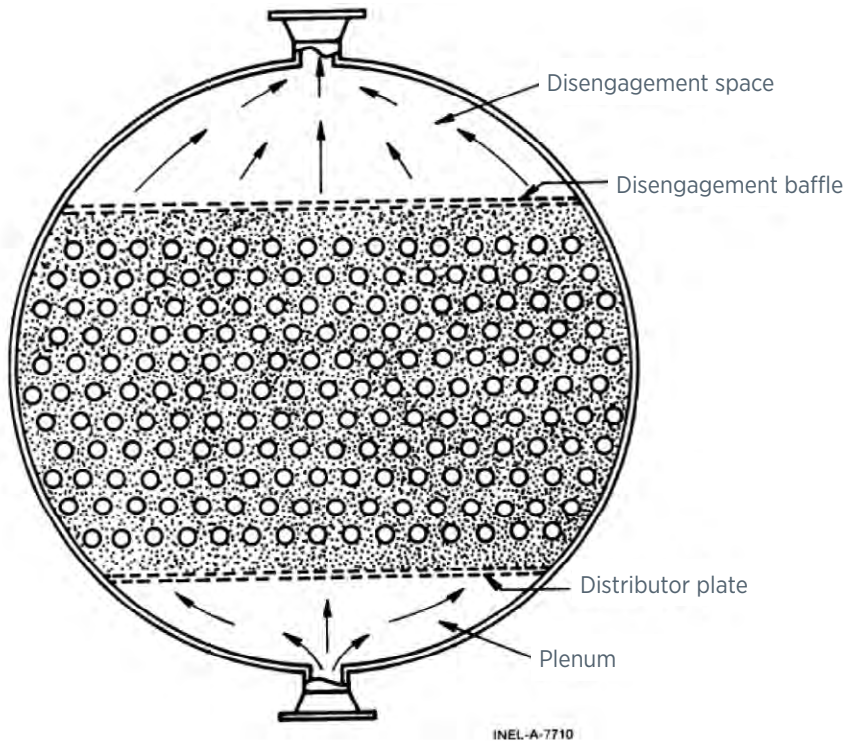


Figure 11. Cross section of fluidized bed heat exchanger

FLUTED TUBE CONDENSER

ORNL conducted research to improve the performance of binary cycle condensers. These investigations sought to improve the condensation heat transfer effectiveness of various working fluids by using tubes with longitudinal flutes on the outer surface. The surface tension of the liquid condensate film on the curved surface of the fluted tubes forced liquid into the troughs, leaving thinned films on the crests. Heat transfer is increased in the regions with the thinned films.⁶⁷ An example of a fluted tube tested by ORNL is shown in Figure 12. Field tests were conducted at both Raft River, Idaho and East Mesa, California; both a shell-and-tube heat exchanger and DCHX were used to vaporize the working fluid. When used with a shell-and-tube boiler, a vertical fluted tube increased the condensing coefficient by a factor of 6 relative to a vertical smooth tube and a factor of 3 relative to a horizontal smooth tube. Field tests demonstrated performance sensitivity to NCGs inherent to operation with direct contact heat exchangers.⁶⁸

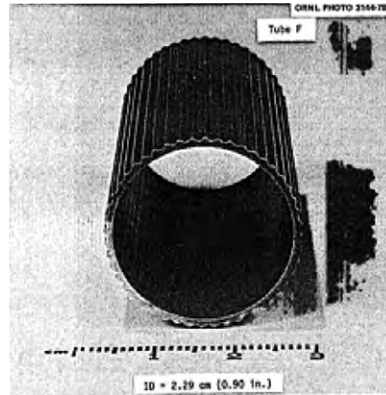


Figure 12. Fluted condenser tube

4.1.2 Total Flow Devices

With a liquid-dominated resource, the cycle with the greatest potential for optimal performance is the one in which geothermal fluid is expanded directly from well head conditions to sub-atmospheric condensing, akin to the steam cycle used with a vapor-dominated resource. Because the fluid is expanded directly from the well head, flash separators or geothermal heaters are not needed, reducing the capital cost. Because the expansion is two-phase, the expander efficiency is less than that achieved with a single-phase, vapor expansion in either a flash or binary cycle turbine. A total flow expander must achieve minimum threshold efficiency to have a performance advantage over conventional cycles.

LLNL conducted a research program to evaluate the use of these expanders as a viable means of generating power from liquid-dominated resources. Testing to identify factors affecting the performance of different types of expanders was conducted under controlled conditions at LLNL's Geothermal Two-Phase Flow Test Facility, as well as in the field at the GLEF in the Salton Sea. Models were developed to characterize two-phase flow in an expander's nozzles and rotor, assess test results, and identify where performance could be improved. Among the devices tested were a Lysholm engine (or helical rotary screw expander),⁶⁹ an impulse turbine,⁷⁰ and a Hero turbine.⁷¹ Under controlled test conditions the Lysholm engine achieved efficiencies from 49 to 55 percent but

was limited by the volumetric expansion of the fluid (and the pressure ratio across the device). Efficiencies achieved with the other expanders were lower.

Other types of expanders in which the inlet fluid was a hot, single-phase liquid were evaluated, including a radial outflow reaction turbine and a velocity pump reaction turbine. Modeling suggested that the velocity pump reaction turbine could produce efficiencies over 50 percent.⁷²

LLNL's work to develop a total flow expander for geothermal applications ended in late 1978. Its work provided the basis for understanding the two-phase expansion process and identifying how performance could be improved.

4.1.3 Enhanced Air-Cooled Condenser Performance

When producing power from lower temperature resources, about 90 percent of the heat extracted from the geothermal fluid is rejected to the ambient. While an evaporative heat rejection system is preferred, geothermal resources are frequently located in regions that lack suitable sources of water to make-up for evaporative losses. Binary plants do not have steam condensate, a flash plant's inherent source of clean water for make-up, and are forced to use sensible heat rejection systems when adequate surface or near-surface water supplies are not available.⁷³ This sensible rejection of heat to the ambient is accomplished using air-cooled condensers. As a result of air's poor heat transfer performance and the significant levels of heat rejected, large condenser surface areas are needed. In addition, due to its low density and specific heat, large volumes of air must be passed through the condenser, requiring significant fan power. Figure 13 shows the relative size of the condensers in an operating binary plant near Mammoth Lakes, California. Air-cooled condensers are located on the periphery of two, identical plants. The geothermal heat exchangers for one plant are shown in the right foreground of the photo between the two outer rows of condensers.

According to EPRI's "Next Generation Geothermal Power Plants,"¹⁰ the contribution of air-cooled condensers to total capital cost ranged from 30 to 45 percent for four representative power plants. In addition to its capital cost, a fan can use 6 to 12 percent of gross generator output. Both capital cost and fan power tend to increase with lower temperature resources. Because of the importance of condensers on a binary plant's performance and cost, DOE pursued two approaches to increase the air-side heat transfer performance using techniques that disrupt boundary layer formation and direct air flow to regions of low heat transfer on the condenser tube's fin surfaces: 1) vortex generators on fin surfaces and 2) air-cooled condensers using tabbed fins.



Figure 13. Air-cooled binary plants near Mammoth Lakes, California

VORTEX GENERATOR CONCEPT

INL investigated using vortex generators on fin surfaces to disrupt the air boundary layer on the fin surface and direct flow into the normally stagnant wake region behind the tube.⁷⁴ Both of these effects increase the local heat transfer on the fin surface. Figure 14 shows the delta vortex generators (“toe-out” configuration) that were used on a circular tube fin (air flows from left to right). (The terms “toe-out” and “toe-in” describe the orientation of the trailing tip of the winglet relative to the air flow. In the configuration in Figure 14, the trailing tips of the winglets point “outward.” Thus, this is the “toe-out” configuration.) It was shown that winglets enhanced heat transfer by 10 to 15 percent, though the enhancements were typically accompanied by increased pressure drop.

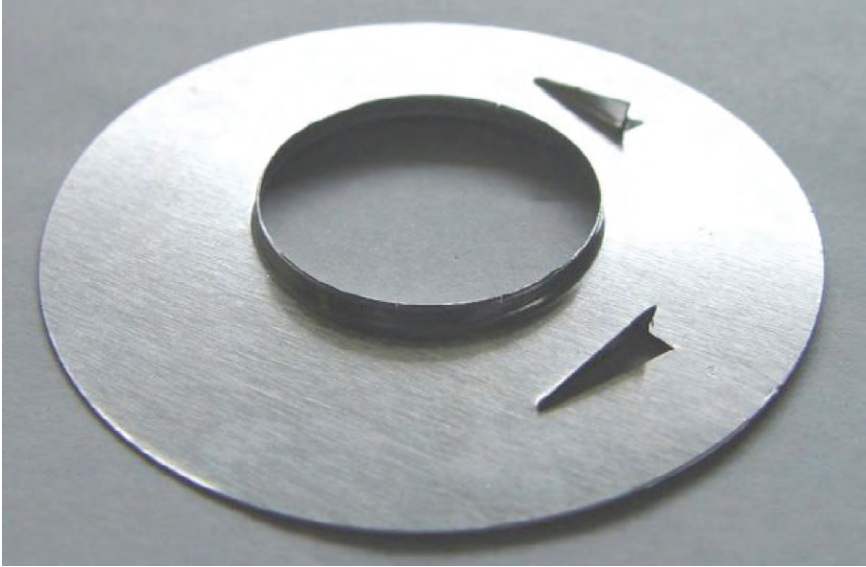


Figure 14. “Toe-out” delta winglets

Initial testing examined the thermal response to the inclusion of different winglet types at different positions on the fin surface. Examples of test results for a circular tube with and without the winglets are shown in Figure 15 (air flow was from the bottom to the top). The increase in heat transfer in the region around each of the winglets (i.e., the “toe-in” configuration in the figure) is clearly shown. The reduction of the size of the wake region on the back side of the tube where heat transfer is low because of the lack of air flow is also shown. Inclusion of the winglets increased the Nusselt number by 20 to 40 percent for both the circular and oval tubes. (The Nusselt number is directly proportional to the heat transfer coefficient). Pressure drop tests confirmed that higher friction factors resulted when the winglets were used.

To facilitate the testing of both heat transfer performance and hydraulic losses of tube bundles, INL developed an open-circuit air-flow loop called the Single-Blow Test Facility (SBTF) that allowed performance testing of tube bundles (four rows of tubes with four tubes per row). Tests were conducted with three fin configurations: 1) a plain fin with no winglets, 2) a “toe-out” configuration, and 3) a “toe-in” configuration.

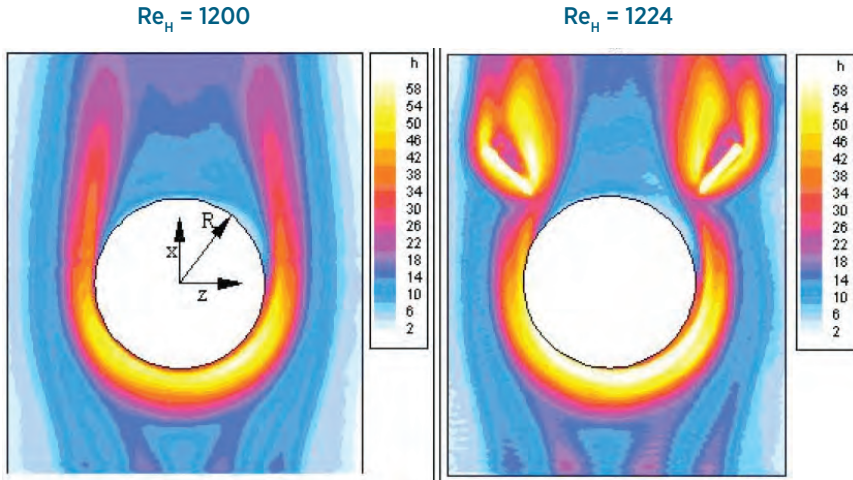


Figure 15. Thermographic test results without (left) and with (right) winglets (“toe-in” configuration)

Figure 16 summarizes pressure drop and heat transfer results as a plot of the friction factor and the Colburn j -factor (heat transfer metric) as a function of Reynolds number for each configuration. Enhancement-1 refers to the “toe-in” winglet configuration, and enhancement-2 to the “toe-out” configuration. As expected, the plain fin (baseline) had the lower friction factor and j -factor. The results indicate the enhanced fins provided greater heat transfer performance (increased j -factor) at the expense of higher pressure losses for the air flow (higher friction factor). The optimal enhancement configuration becomes a trade-off between the benefit of the increased heat transfer and the additional fan power associated with a given enhancement configuration. The data collected did not facilitate a direct comparison of the results for the enhancements; one of the enhanced bundles had a different fin configuration (lower fin pitch). The impact of misaligning the winglets was tested. Results indicated that misalignment of the winglets adversely impacted performance, though it was probable that they would still provide some performance benefit.

INL’s work on developing winglet vortex generators was supplemented by a grant from the Japanese New Energy and Industrial Technology Development Organization (NEDO). The grant supported numerical studies by a doctoral student and equipment purchases, including equipment used in the SBTF. NEDO funded work on the winglet design at Yokohama National University in Japan and the Indian Institute of Technology in Kanpur, India, complementing DOE’s research efforts at INL. These independent investigations produced results similar to those obtained by INL. While they identified very promising configurations, results were received after INL testing ended.

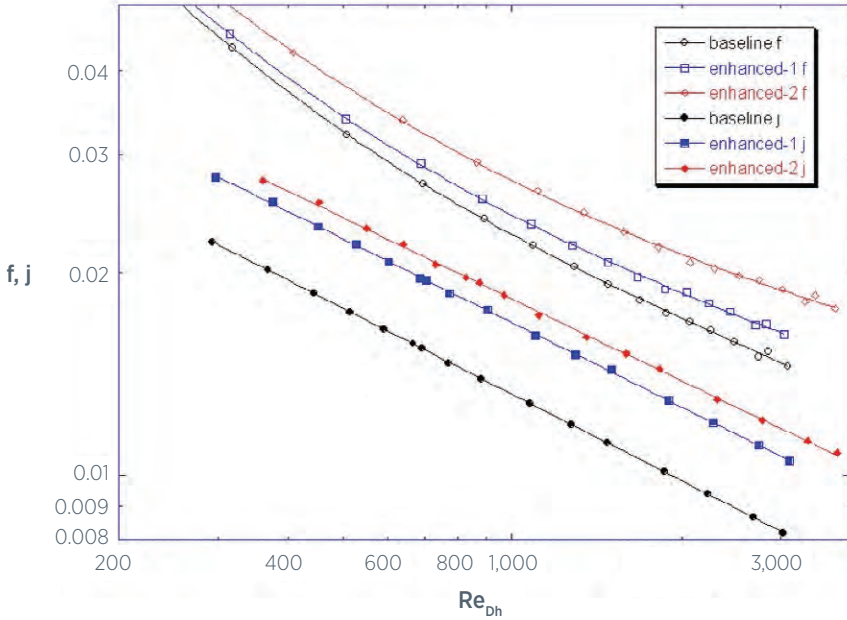


Figure 16. Heat transfer and hydraulic performance test results from the Single-Blow Test Facility

ENHANCEMENT OF AIR-COOLED CONDENSERS USING TABBED FINS

NREL conducted analytical and experimental R&D to evaluate new fin concepts applicable to air-cooled condensers. NREL's first concept—transpired fins—demonstrated very high heat transfer enhancements, but also incurred a high pressure drop penalty.⁷⁵⁻⁷⁶ Subsequent work focused on using small tabs punched in the fins to improve the ratio of heat transfer enhancement to pressure drop. Figure 17 illustrates this concept applied to a plate fin for ½-inch tubes (on the left) and a photograph of a circular fin with tabs (on the right).

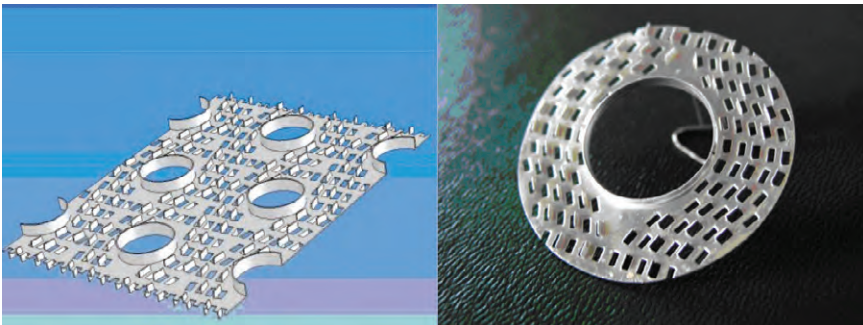


Figure 17. Tabbed fin design for plate (left) and circular fins (right)

Perpendicular tabs protruded from both sides of the fin, extending about halfway across the gap between adjacent fins. The advantages of this concept are that 1) each tab starts a new boundary layer, 2) each tab extends into the coolest air flow, 3) the holes left by the tabs interrupt the boundary layer on the main fin surface, and 4) proper tab size and orientation can be used to gradually direct the air flow into specific regions, such as the wake region behind the tubes. The tabs add frictional and form drag, but because the tabs are both aligned with air flow and direct flow to reduce the form drag behind tubes, the pressure penalty is small. The holes created in the surface of the fin when the tabs are made inhibit the conduction heat transfer paths through the fin. By keeping the fin porosity below about 30 percent and using non-uniform tab patterns, the fin efficiency penalty associated with the holes is minimized.

Optimal tab dimensions, spacing, and orientation were initially determined using a fluent computational fluid dynamics (CFD) model. Flow visualization tests were then used to examine the effect of tab configurations on flow along fin surfaces. Pressure drop measurements were taken during these tests and used to adjust the tab angles to minimize total pressure drop. Photographs from these tests are shown in Figure 18 for plain (on left) and tabbed (on right) circular fins on 1-inch tubes (flow is left to right in these figures).

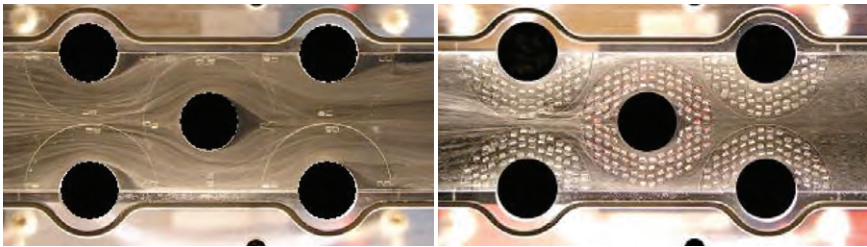


Figure 18. Flow visualization tests with plain (*left*) and tabbed (*right*) circular fins

The impact of the tabs on air-side heat transfer was determined using a transient or single-blow test rig. These tests yielded air-side heat transfer coefficient increases from 50 to more than 100 percent, showing proof-of-concept. Investigations were then conducted under steady-state conditions with tube bundles having ½-inch tubes and plate fins, a configuration of interest to industry partner Super Radiator Coil (SRC). Tested bundles used the tab-fin design, as well as plate fins and high-performance louvered fins.

The results for the eight fin-per-inch bundles (plain, tabbed, and louvered) are shown in Figures 19(a) and 19(b). As Figure 19(a) shows, louvered fins had the highest heat transfer rate, providing about 40 percent more total heat transfer than plain fins. The tabbed fins provided about 29 percent more heat transfer than plain fins. As Figure 19(b) shows, both enhanced fins also incurred pressure drop

penalties: 80 percent more with the louvered fins and 50 percent more with the tabbed fins. The performance evaluation criteria (PEC) for the louvered and tabbed fins were found to be 1.18 and 1.17, respectively, which represented the increase in heat transfer per unit of fan power. The PEC used was a ratio of the relative increase in the Colburn j-factor to the relative increase in the friction factor.

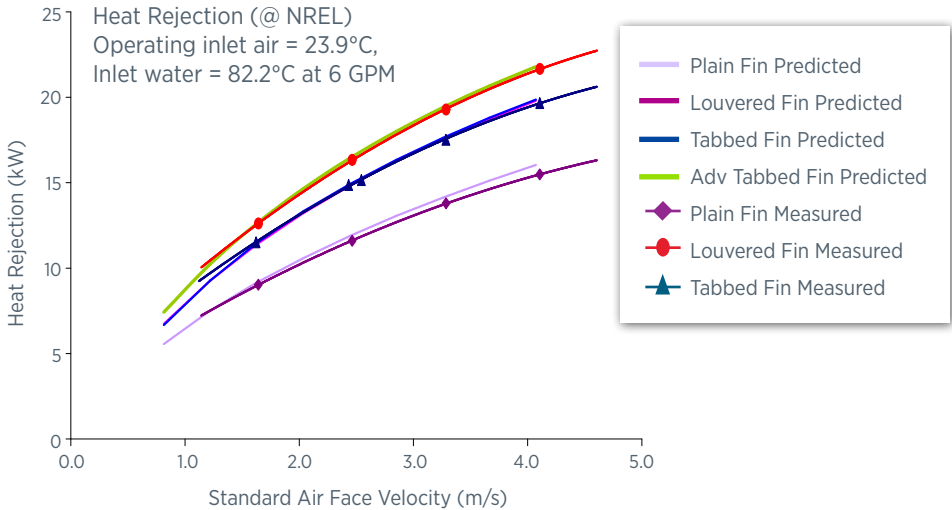


Figure 19(a). Heat rejection test results with plate fins and 1/2-inch tubes

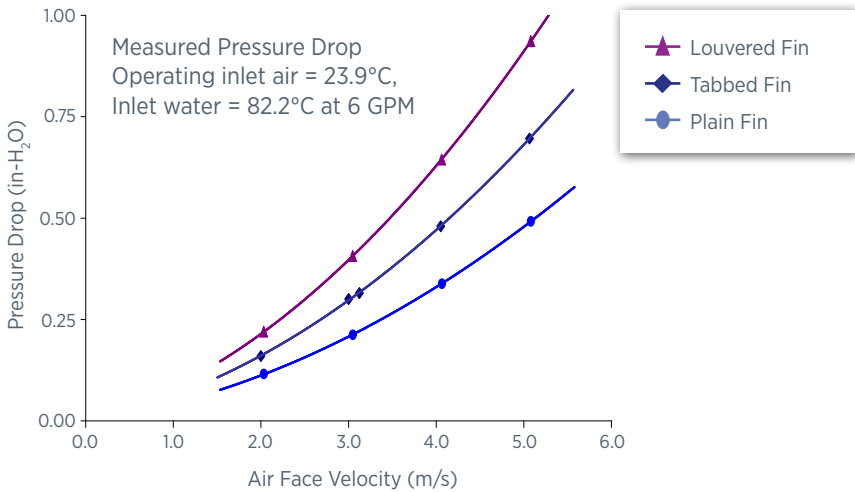


Figure 19(b). Measured pressure drop test results with plate fins and 1/2-inch tubes

The high performance of the first generation tab design afforded many opportunities to improve the design. Modeling results suggested that the PEC for the eight fins per inch (FPI) heat exchanger could be raised from the measured 1.17 to a predicted 1.22. Modeling also indicated that the tabs should be able to provide 10 to 12 percent more heat transfer at the same fan power when applied to circular fins on ½-inch tubes. This enhancement would increase net power output by about 4 percent, decreasing the cost of electricity by 0.25 cents per kWh, assuming there was no additional manufacturing cost associated with the tabs.

The tab concept was most easily applied to plate fins by a punching station commonly used in fabricating tube-and-plate fin heat exchangers. It can also be applied to finned tubes that employ individual fins. Adding tabs to tension-wound fins (e.g., the McElroy design used in geothermal power-plant condensers) is significantly more difficult because of material stretching and alignment issues. The concept has not been explored thoroughly enough to be ruled out, however, and has been pursued with McElroy Manufacturing Company.

INDEPENDENT TEST OF ENHANCEMENT TECHNIQUES

In 2004, DOE directed researchers at NREL and INL to conduct tests of their concepts on an equivalent basis to determine whether to continue funding development of either concept. Because air-cooled condensers in binary plants typically use one-inch diameter tubes with circular fins that are embedded or tension wound onto the tubes, this was the configuration selected for testing.

INL and NREL researchers incorporated their enhancement by punching either winglets or tabs into the individual fins that then were used in fabricating tube bundles. Three identical heat exchanger bundles were fabricated for testing: 1) one with plain fins (unmodified), 2) one with the tabbed fins, and 3) one with the vortex generators (“toe-in” winglets). Intertek Testing Services, an independent test facility in Philadelphia, Pennsylvania tested the three heat exchangers at four different air flow rates (i.e., face velocities of 400, 600, 800, and 1,000 feet/minute) with hot water flowing through the tubes.

Results of the test are shown in terms of the percentage increase in overall heat transfer compared to plain fins at the same fan power in Figure 20. The bundle with the tabbed fins (T-fin) provided about 4 percent more heat transfer at the same fan power. This was less than the 10 to 12 percent improvement that researchers expected (T-fin Predicted). The bundle with the INL winglet pair had effectively the same heat transfer performance as the bundle with the plain fins and a slightly higher pressure drop. Researchers at both NREL and INL conducted post-test evaluations to determine possible explanations for the less-than-expected performance.

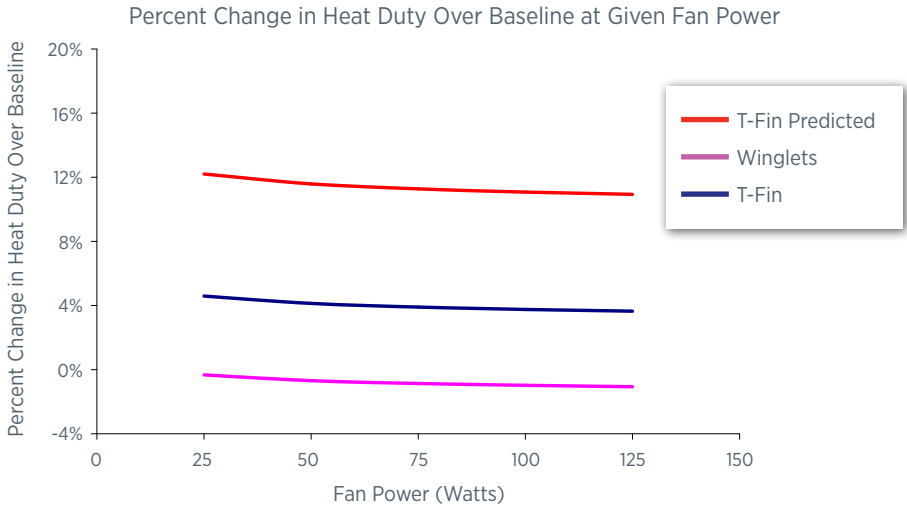


Figure 20. Independent test results for tabbed fin and winglet vortex generator concepts

Tabbed fin

The post-test investigation of the selected tab pattern for the circular fins was conducted via flow visualization and computational fluid dynamics flow analysis with Fluent, a CFD software package. This investigation indicated that the tabs were at angles too sharp to adequately reduce pressure drop due to tube wakes. The result was a 70 percent increase in pressure drop, compared to the 40 percent penalty expected. With proper design, researchers predicted a 10 to 12 percent improvement in performance.

Winglet vortex generators

Funds were not available to repeat the SBTF tests, so researchers re-examined the test results from prior SBTF tests using an approach by Heat Transfer Research, Inc. to account for the differences in fin spacing. The re-evaluation suggested that results from the Intertek testing should have been expected. The SBTF tests indicated the friction factor for the enhancement would be 1.0 to 1.1 times that of a plain tube. The projected 13 percent increase in the air side heat transfer coefficient from the enhancement would increase the overall heat transfer coefficient from 1 to 5 percent. The Intertek results showed a maximum heat transfer enhancement of ± 1 percent and a pressure drop increase of 3 to 6 percent. This post-test analysis indicated the “toe-out” winglet configuration should have been selected for testing at Intertek.

As a result of this testing, DOE elected to continue the development of the tabbed fin design at NREL and terminated INL's vortex generator investigations. NREL's efforts were subsequently ended when all energy conversion research activities were terminated in 2005-2006.

4.1.4 Advanced Direct-Contact Condenser

NREL developed an ADCC using sophisticated geometric shapes to provide optimal surface area for condensing spent steam.⁷⁷ Condensation of spent steam is a key part of the power cycle in electricity-generating plants. Direct-contact condensers mix cooling water with turbine exhaust steam in an open vessel to condense the steam rather than condensing the steam on the surfaces of coolant tubing (surface condensers). Most existing direct-contact condensers use only perforated plates to provide surface area for condensation. An ADCC incorporates sophisticated geometric shapes to provide optimal surface area for condensing spent steam. An example is shown in Figure 21. In addition to providing surface area, these “packing structures” channel the steam and water for maximum contact with each other. A computer code is used to evaluate the thermal performance of potential packing structures and to identify the optimal packing for a particular condenser and power plant. The program also models chemical reactions in the spent steam and cooling water.

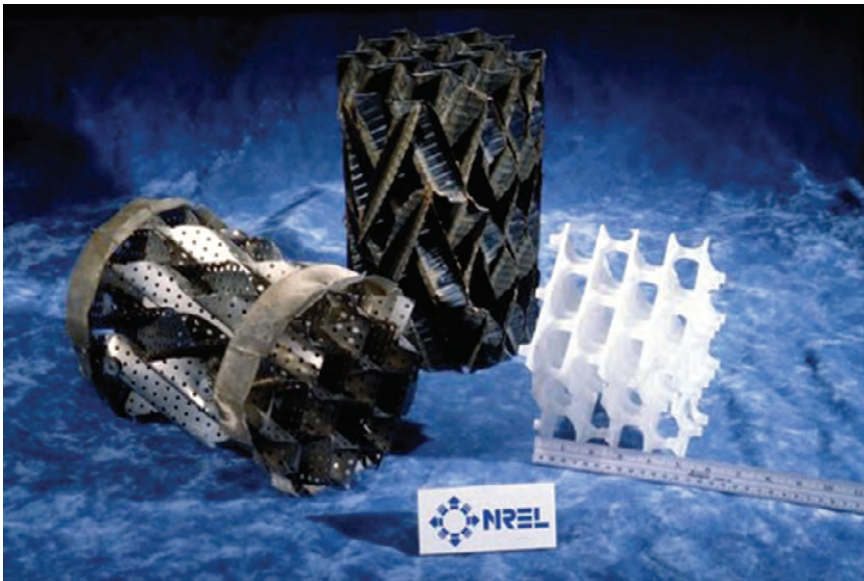


Figure 21. Examples of structured packing materials used in the advanced direct-contact condenser

ADCC technology was employed at The Geysers Unit 11 to validate its potential to improve plant performance and partitioning (separation) of NCGs and steam. Adding the enhanced packing structures to the existing condenser increased production efficiency by 5 percent, while cutting the chemical cost for hydrogen sulfide emission abatement in half. Because the condenser had been the limiting factor for Unit 11, the refurbishment increased total power generation potential by 17 percent.⁷⁸

4.1.5 Component Development for Ammonia/Water Power Cycles

NREL designed a prototype ammonia absorber-cooler (air-cooled) that 1) allowed for mixing of ammonia vapor with lean liquid (water) inside the cooler, and 2) enhanced the air-side heat transfer coefficient. Design objectives were to reduce condenser size and lower the turbine back-pressure to increase turbine output. The concept incorporated fins on the air-side of a plate heat exchanger that would reduce air-side pressure drop, making it possible to increase the heat transfer coefficient by increasing the air velocities.⁷⁹ Researchers selected a vertical plate heat exchanger design as providing the best opportunity for accomplishing the desired mixed absorption/condensation process when combining lean liquid extracted from the high-pressure side of the cycle with the turbine exhaust. Tests were conducted to determine the most effective air-side fin geometry. Heat transfer and pressure drop correlations were developed for that fin arrangement. Preliminary designs were made for liquid and vapor distribution systems. Different methods for manufacturing and bonding the plates and fins were also examined. These were incorporated into a procedure that was developed for the design and fabrication of a finned plate heat exchanger operating at high pressures.

4.1.6 Noncondensable Gas Removal for Steam Plants

NREL researchers performed a screening analysis to compare six different methods of removing NCGs from geothermal steam power plants.⁸⁰ The analysis defined the methodologies and compared the performance and economics of selected gas removal systems. The gas removal methods evaluated included five vacuum system configurations that used the conventional approach of evacuating gas-vapor mixtures from the power plant condenser system, as well as a “reboiler” process system that condensed and re-evaporated raw geothermal steam upstream of the turbine. Analysis indicated three gas removal options had the potential to be economic. Two hybrid vacuum system configurations and the reboiler process yielded positive net present value results over a wide range of gas concentrations. The hybrid options appeared favorable for both low- and high-temperature resource applications. The reboiler appeared better suited for low-temperature resource applications for gas levels above about 20,000 parts per million by volume (ppmv).

4.2 Power Cycle Development

In order to develop geothermal power cycles, DOE R&D focused on binary cycle technology for lower temperature resources—largely because the economic feasibility of generating power from this resource base was considered marginal at best. Technologies for higher temperature resources were considered more mature; there was less issue with the viability of power production from this higher quality resource base. R&D emphasized developing more efficient binary cycle technologies. The impetus for pursuing more efficient power cycles was that they would be needed to offset well field development costs that would include exploration and drilling.

Studies in the mid-1970s by EPRI and the Massachusetts Institute of Technology (MIT)⁸¹ suggested that well field capital costs could account for a significant portion (i.e., 30 to 60 percent) of a total project's capital cost. This contribution increased with the lower resource temperatures. DOE's involvement at Raft River, Heber, and East Mesa (Sperry's Gravity Head System) lent credence to the magnitude of the well field costs in these studies. When the well field costs approached the magnitude of plant costs, it could be shown that plants that more completely used the energy in geothermal fluid could have lower power generation costs. The premise that field and plant costs would be of similar magnitude was the basis for the subsequent power cycle development in INL's Heat Cycle Research Program activities that were carried out through the 1980s and into the early 1990s.

4.2.1 Heat Cycle Research Program

By the early 1980s, efforts to develop binary cycle technologies had been largely consolidated in INL's Heat Cycle Research Program. This work had its origins in the assessment of power cycle improvements that could be incorporated into the next generation binary plant for Raft River.

In identifying cycles with the potential to improve performance, geothermal fluid, also referred to as the brine utilization or the specific power output, was used as the performance metric. Regardless of the name used, it is the net power produced by the plant per unit mass of geothermal fluid (watt-hours per pound). To improve performance, investigators chose to pursue those that would reduce irreversibilities (losses of available energy) associated with heat transfer processes, in lieu of increasing pump or turbine efficiency. The irreversibility associated with these heat transfer processes is reduced by minimizing the average temperature difference between the working fluid and either the geothermal fluid or cooling fluid. Though this can be accomplished by increasing heat exchange surface area, there are practical constraints limiting the extent to which area can be increased without cost becoming prohibitive.

Early binary cycle development examined cycles that reduced irreversibility by performing heat addition and heat rejection at multiple pressures or levels. This concept of a multiple boiling cycle was incorporated into DOE’s 5-MW Raft River binary power plant. It was subsequently shown that a triple-boiling, triple-condensing cycle provided significantly improved performance relative to the Raft River 5-MW plant.⁸² Although multiple boiling cycles reduce the irreversibility associated with heat addition, they cannot negate the irreversibility resulting from isothermal boiling at each pressure. Investigators were able to show that by using a supercritical cycle, where the working fluid is vaporized at a pressure above its critical pressure, one could approach the idealized heat addition process where the temperature profiles are nearly parallel (i.e., a near constant temperature difference throughout the entire heat addition process).⁸³

When a pure fluid is used, a supercritical cycle does not address the irreversibility associated with the fluid’s isothermal condensing. This cycle inefficiency was addressed by the use of multiple component working fluids. For a fixed pressure, mixed working fluids do not condense (or boil) at a constant temperature. By adjusting the relative concentration of the mixture components, it was possible to better match the temperature profiles of the cooling fluid and working fluid mixture during the condensation process. A supercritical cycle with mixed working fluids is shown on the temperature vs. enthalpy plot in Figure 22 (WF = working fluid, GF = geothermal fluid, and CF = cooling fluid).

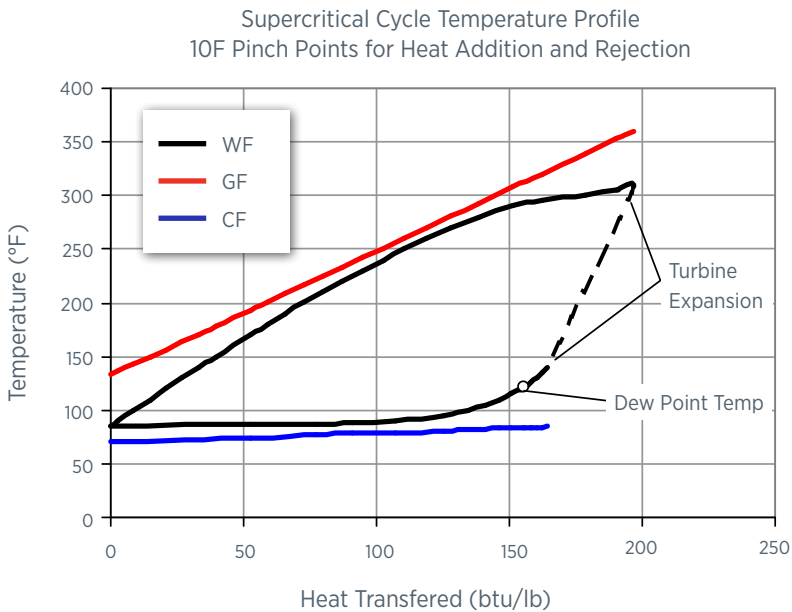


Figure 22. Heat addition and rejection processes with mixed working fluid

The benefits of using a supercritical cycle with mixed working fluids were projected for both the 138°C (280°F) Raft River resource and the 182°C (360°F) Heber resource. With the Raft River resource, a mixture of 90 percent propane and 10 percent isopentane in a supercritical cycle had 20 percent greater brine effectiveness than the dual boiling cycle used in the plant. With the Heber resource, a supercritical cycle with the optimized working fluids and recuperators was projected to produce approximately 14 percent more power than the binary demonstration plant (which also used mixed working fluids). By designing the Heber condenser to achieve the counter current flow paths, performance could be increased by at least 6 percent.

Supercritical cycles were also evaluated where the turbine inlet conditions were modified to produce expansions having equilibrium conditions within the two-phase region.⁸⁴ These turbine expansions began at supercritical pressures, entered the two-phase region, and then exited the two-phase region—exhausting the turbine as a slightly superheated vapor. These expansions are illustrated on the temperature versus entropy plot shown in Figure 23. It was estimated that these expansions would provide an additional increase in-cycle performance of up to 8 percent if there was no degradation in the turbine efficiency.

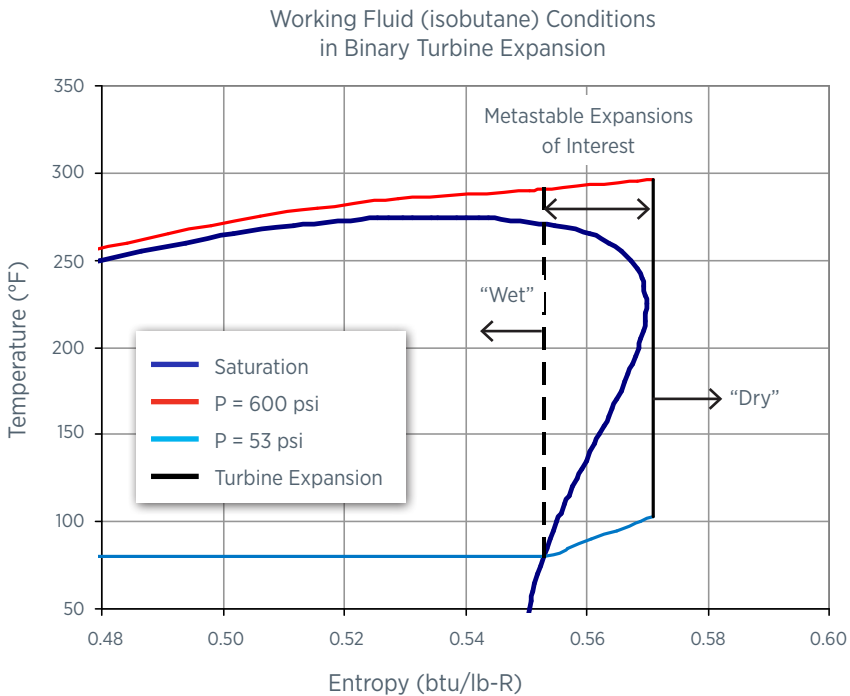


Figure 23. Turbine expansions with modified inlet conditions

Evaluation of cycle improvements was not limited to using mixed hydrocarbons. Halocarbon and ammonia-water mixtures were also evaluated. The preliminary analysis of the use of mixed halocarbons indicated that plant performance would be at least as good as that obtained with hydrocarbon mixtures.⁸⁵ The analysis of ammonia and ammonia-water mixtures indicated that while pure ammonia would not perform as well as hydrocarbons using a 138°C (280°F) resource, it would likely reduce the component sizes in a power plant. Ammonia was not considered a viable alternative to hydrocarbons at higher temperatures because of the high operating pressures required to produce optimal cycle performance.

In addition, the performance of an ammonia-water mixture in a Rankine Cycle for a 182°C (360°F) resource was evaluated. It was found that the mixture would provide a slight performance benefit relative to the Heber plant, and it would likely lower the cost of power because of reduced component sizes.⁸⁶ The predicted cycle performance using ammonia-water mixtures was contingent upon the use of turbine exhaust recuperators. If recuperators were not used there would be no benefit to using ammonia-water mixtures at this resource temperature.

The use of ammonia-water as a geothermal working fluid was included in an analysis of the Kalina Cycle technology in geothermal power applications.⁸⁷ In addition to ammonia-water, mixtures of hydrocarbons and halocarbons were evaluated in this cycle. Though some advantage was found with the Kalina cycle, its performance was less than that of the supercritical cycle with mixed hydrocarbons (Rankine cycle). A subsequent comparison with the Kalina System 12 indicated its predicted performance was greater than that of the Heber plant, but less than that of the recuperated, supercritical cycle with hydrocarbon mixtures.⁸⁸ The Kalina System 12 cycle used ammonia-water, but did not have the distillation subsystem. No attempt was made to quantify the relative cost of the Kalina System 12 and the advanced Rankine cycle.

In 1991, an analysis was conducted to identify where further improvements in the binary cycle might be achieved.⁸⁹ The performance of an idealized binary cycle having an idealized working fluid that minimized irreversibilities in the heat exchange processes was assessed for nominal heat exchanger pinch points and rotating equipment efficiencies. The projected performance of the idealized cycle was then compared to that of advanced and conventional cycles. Figure 24 shows the performance of these cycles relative to the ideal cycle with practical operating constraints.

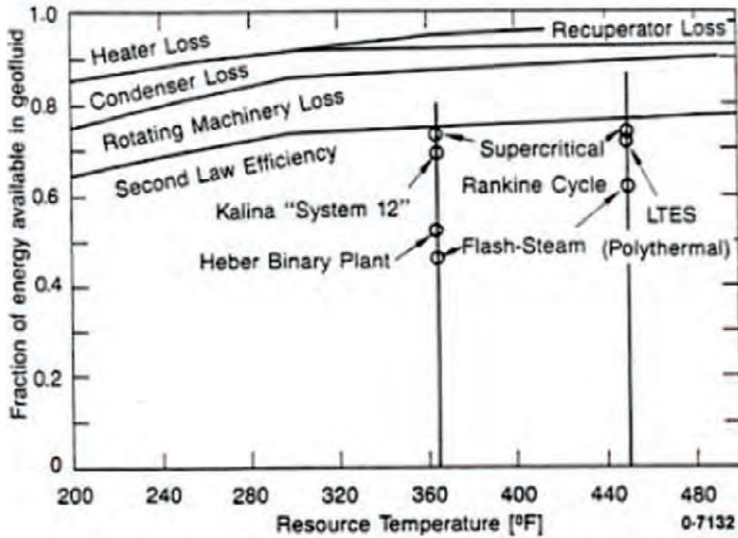


Figure 24. Binary cycle practical limits of performance

The comparison indicated that the supercritical cycle with mixed hydrocarbons (Supercritical Rankine Cycle) and the Kalina Cycle performances approached the practical limits of performance defined by the idealized cycle. While this analysis was not a definitive evaluation of energy losses in the power cycles, it indicated that 1) the performances of the advanced cycles were approaching practical limits, and 2) any further significant increases in efficiency would be difficult without increasing turbine efficiency or reducing heat exchanger temperature differences (i.e. by increasing heat exchanger sizes and costs).

ADVANCED CYCLE BENEFITS

The impact that cycle improvements would have on power cost was measured utilizing a "value analysis" technique developed by INL researchers.⁹⁰ The technique examined the relative impact of different cycle concepts on the size and cost of components in a 50-MW reference plant. It then used a capital cost distribution developed for the major process systems and equipment items to determine the relative impact of a cycle improvement on the plant's capital cost. In evaluating the effect of the advanced cycles on the cost of power, it was assumed that costs associated with the well field accounted for 50 percent of the cost of power. Five of the scenarios considered are shown in Table 2. (In this table iC4 is isobutane, iC5 is isopentane, and C7 is hexane.) Note that the indicated changes in power output and the cost of electricity are relative to the first scenario shown; this scenario is representative of the Heber 50-MW Binary Demonstration Plant.

Table 2. Results of value analysis showing effects of advanced cycles on cost of electricity

Scenario	1	2	3	4	5
Working Fluid	88% iC4; 12% iC5	96% iC4; 4% C7	96% iC4; 4% C7	100% iC4	96% iC4; 4% C7
Heater Pressure (psia)	580	600	600	600	700
Condenser Pinch Point (F)	10	10	10	10	10
Co-current Condensing	yes	no	no	yes	no
Counter Current Condensing	no	yes	yes	no	yes
Outlet Temperature Constraint (F)	160°	160°	160°	no	no
Recuperation	no	yes	no	no	no
Metastable Expansion	no	no	no	no	yes
Δ Power	1	20%	8%	12%	30%
Δ Cost of Electricity	1	-13%	-4%	-8%	-19%

The analysis showed that the supercritical cycle with optimized turbine inlet conditions and proper working fluid selection could provide significant cost reductions relative to the reference plant. It also illustrated the adverse impact of the outlet temperature constraint to prevent silica precipitation and the benefit that recuperation (i.e., the use of turbine superheat for preheating the working fluid) could have on reducing this impact. These potential benefits became the basis for further investigations by INL to validate performance improvements projected for the supercritical cycle using mixed working fluids.

ADVANCED CYCLE VALIDATION

Supercritical cycles with mixed working fluids

The test program to validate performance improvements from using supercritical cycles with mixed working fluids was conducted at the Heat Cycle Research Facility (HCRF). The HCRF was installed at the DOE GTF in California's Imperial Valley in 1983. The HCRF was constructed in part with equipment from the prototype power plant at Raft River.

For mixtures testing, a vertical, in-tube condensation design was used. This design was a major departure from the water-cooled design typically used in binary plants, where condensation occurs on the outside of horizontal tubes. The HCRF design was selected to achieve both the counter-current flow paths and integral condensation of the working fluid that are required to reduce the irreversibility associated with condensing. Integral condensation refers to keeping the vapor and

liquid phases in equilibrium during the entire condensation process in order to achieve the desired non-isothermal condensation.

Figure 25 is a photo of the HCRF shortly after it was installed at the GTF. The HCRF was composed of three skids. The piping skid (middle) was composed of the pump, turbine generator, and control valves. On either side were the hairpin supercritical heat exchangers (on the right) and vertical condenser (on the left).



Figure 25. Heat Cycle Research Facility with a vertical condenser orientation

Vertical condenser orientation

Initial testing at the HCRF was conducted with the condenser in the vertical position, as depicted in Figure 25.⁹¹ Testing was performed with propane, isobutene, isopentane-propane, and hexane-isobutane. Initial testing focused on evaluating the performance of the supercritical heat exchangers and the condenser. In addition to changing working fluids and mixture compositions, pressures, flow rates, and vapor superheat levels were also altered for both the heaters and condenser.

Data collected for both the heat exchangers and condensers were evaluated using Heat Transfer Research, Inc. (HTRI) design codes. Using the measured working fluid composition, the design codes were used to predict the size of the heat exchanger that would be required to produce the measured test conditions (e.g., flows, pressures, and temperatures), assuming that they were the specified conditions for the heat exchanger. The match of the predicted size to the actual

size provided an indication of the reasonableness of the HTRI predictions. The shell side of both the heaters and the condenser were instrumented to provide a temperature distribution of the shell side fluid as a function of the heat exchanger area. The ability of the HTRI codes to match these temperature profiles was an additional indicator of the adequacy of these design tools. Limited testing was also performed with an axial flow impulse turbine that confirmed this component would perform as predicted with the mixed working fluids.

Testing resolved a number of concerns related to the supercritical heat addition portion of the advanced cycle. Issues remained regarding the atypical design of the HCRF condenser. It was postulated that if a binary plant condenser used in-tube condensation, it would be designed with a nearly horizontal tube bundle, or in the case of an “A-frame” condenser, at an intermediate orientation.

Non-vertical condenser orientations

In order to examine performance at more typical tube orientations, the HCRF condenser skid was modified to orient the condenser first at a 10-degree angle and then at a 60-degree angle off horizontal.⁹² A photo of the HCRF condenser in the near horizontal (10-degree) orientation is shown in Figure 26. During testing at these condenser orientations, provisions were made to reverse the cooling water flow direction in the condenser and temporarily plug approximately half of the condenser tubes. These additional test parameters allowed researchers to further test the ability of the HTRI condenser codes to predict the condenser performance.



Figure 26. Heat Cycle Research Facility with the condenser at a 10-degree orientation

Metastable turbine expansion investigations at the HCRF

Condensation behavior investigation

The HCRF investigations of metastable turbine expansions initially examined the condensation behavior of these expansions. This was done using a converging-diverging nozzle that replicated the isentropic expansion process in a binary turbine's nozzles. The nozzle contained a window that allowed the expansion of the high-pressure vapor to be observed visually. This observation was assisted by passing a laser beam along the length of the nozzle and detecting any scattering of the beam as droplets formed. Testing focused on the use of isobutane as the major working fluid component. (Propane does not have a retrograde dew point curve on a temperature-entropy plot.) Results of the nozzle tests indicated that the nozzle expansion would support a supersaturated vapor until the maximum equilibrium moisture levels increased above 4 to 5 percent.⁹³ Following nozzle testing, two turbines were tested with the modified inlet conditions to determine the effect of the metastable expansion on the turbine performance.⁹⁴

Axial flow impulse turbine testing

The first turbine tested was a single-stage, partial admissions, axial flow impulse turbine. Testing was conducted using isobutane and a mixture of 95 percent isobutane and 5 percent hexane (mass fraction). The turbine was tested at supercritical inlet pressures, with the inlet temperature incrementally decreased until the turbine expansion was within the two-phase region.

The impulse turbine's performance during testing with the isobutane working fluid is shown in Figure 27. The inlet condition is defined as the difference between the inlet entropy and the dew point entropy at the exhaust pressure. If the difference is greater than zero, the vapor exhausting the turbine is superheated. The maximum dew point entropy defines the point at which some portion of the turbine expansion occurs within the two-phase region. The entropy difference that produced "wet" turbine exhaust conditions is also shown. Results indicated that the turbine efficiency was not significantly affected until the actual exhaust conditions were within the two-phase region.

A test series was conducted with this turbine where the turbine expansion entered, but it never exited the two-phase region. The tests were conducted at an inlet pressure of 600 pounds per square inch absolute (psia). For the most extreme (i.e., highest potential for moisture) condition tested, the turbine inlet temperature was $\sim 130.5^{\circ}\text{C}$ (267°F)—well below isobutane's critical temperature. At the extreme inlet conditions the measured turbine efficiency was 59 percent. Though this testing produced significant decreases in turbine efficiency, brine effectiveness continued to increase. At the lowest inlet temperature and turbine efficiency, brine effectiveness was higher than that achieved with the completely "dry" expansion. The testing with the mixed working fluid produced similar results, both in terms of the

magnitude of the turbine efficiencies and the effect of the modified inlet conditions on that efficiency.

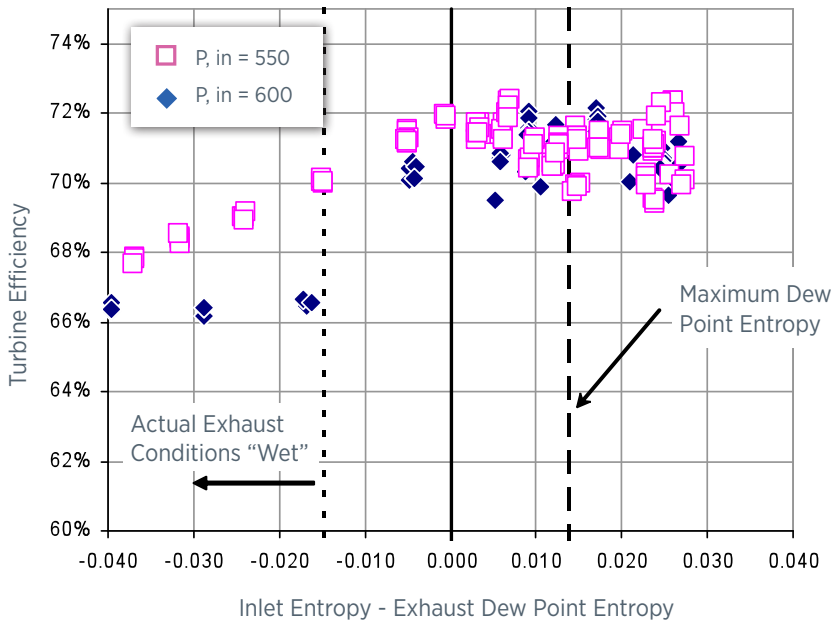


Figure 27. Heat Cycle Research Facility impulse turbine performance with isobutane and modified inlet conditions

Radial inflow reaction turbine testing

Next, testing was conducted with a full admission, radial inflow reaction turbine. The design conditions for this turbine were nominally the same as those for the impulse turbine. Testing with this turbine was conducted at supercritical inlet pressures using both an isobutane working fluid and a 95 percent isobutane-5 percent hexane mixture. The efficiency of this turbine was less than that of the impulse turbine; however the performance difference was secondary to determining the impact of the “wet” expansions on the turbine performance.

Figure 28 shows the impact of the modified turbine inlet conditions on the radial inflow turbine’s performance. Efficiency is presented as the ratio of the turbine efficiency at a given condition to its efficiency at the reference condition during that period of testing. Results indicate that there was minimal impact on the turbine efficiency until the inlet entropy falls below the dew point entropy at the exhaust pressure.

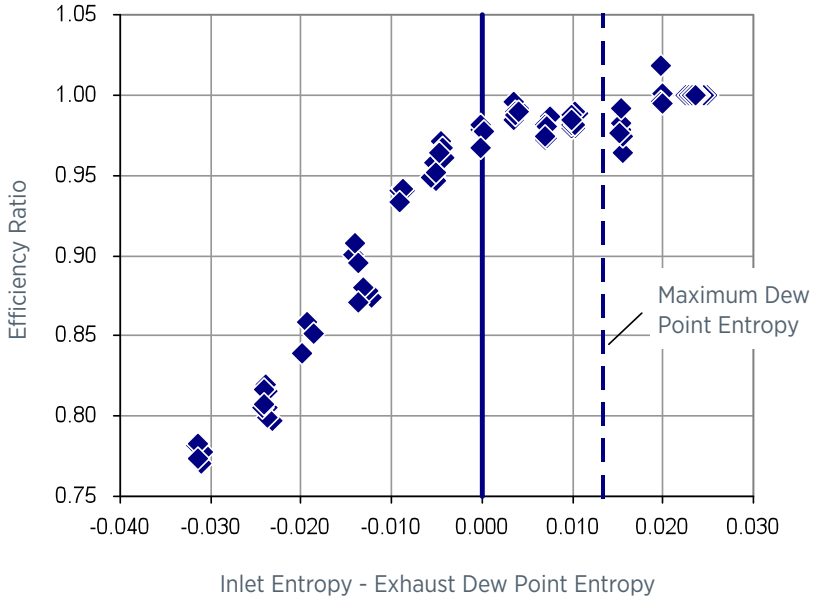


Figure 28. Effect of metastable expansions on radial inflow turbine performance

Testing with both turbines indicated that the impulse turbine would allow for operation at lower inlet entropies (temperatures) before its performance was impacted. This higher tolerance for moisture formation probably resulted because the entire expansion process occurred in the impulse turbine's nozzles. In the reaction turbine, a portion of the expansion occurs in the turbine rotor. As a consequence, once the expansion enters the two-phase region, the vapor exhausting the reaction turbine's nozzles will always have a higher "equilibrium" moisture level.

Reaction turbine testing at the HCRF ended in the summer of 1994. The HCRF was shut down in September of the same year.

Metastable expansion investigations at commercial power plant

The metastable turbine expansion investigations at the HCRF raised industry's interest as to whether these expansions could be used to increase or sustain performance in existing plants. With the assistance of the CE Holt Company and Rotoflow, INL entered into an agreement with Mammoth Pacific Geothermal, LP to operate a commercial plant (MPI-100) turbine for up to six months with expansions that passed through the two-phase region.

The extended investigation began in November 1995. For this test the radial inflow reaction turbine operated at subcritical pressures, with minimal superheat entering to the turbine to assure that a portion of the turbine expansion was within the two-phase region.

Relative to its sister plant, MPI-200, the brine effectiveness at MPI-100 increased by 10 to 20 percent. Because of the increased performance, Mammoth Pacific Geothermal, LP agreed to continue testing with modified inlet conditions. In the spring of 1997, the MPI-100 facility was shut down for maintenance, allowing the turbine rotor and vanes to be removed for visual inspection. This inspection revealed what plant personnel considered typical wear to the rotor and vanes. The turbine efficiency over this period is shown in Figure 29 as a function of the ambient air temperature. The higher baseline efficiency reflects operation with the turbine variable position nozzles fully open. (Throttling with the nozzles reduces turbine efficiency.) Results indicated there was no decline in the turbine's efficiency during the period of operation with the modified turbine inlet conditions.⁹⁵

Mammoth subsequently modified the operation at its other facilities to minimize the superheat entering the turbine and maximize the amount of power produced.

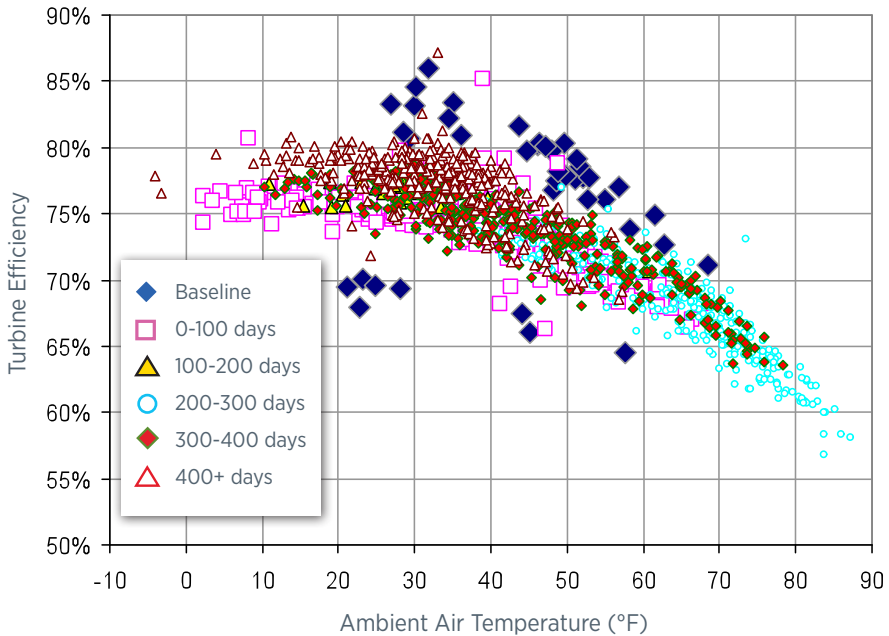


Figure 29. Variation in MPI-100 turbine efficiency during investigation

4.2.2 Binary Cycle Improvement – Post Heat Cycle Research

By the 1990s, DOE had phased out its dedicated physical test facilities. Though industry had deployed the binary cycle in several commercial facilities, additional work was needed to improve operability, incorporate efficiency improvements, and lower the cost of electricity generation. Subsequent efforts by DOE to improve the binary cycle turned to analysis.

VALUE ANALYSIS OF BINARY PLANTS

NREL developed the Cycle Analysis Simulation Tool (CAST) computer model to perform value analysis for small, low- to moderate-temperature binary geothermal power plants. The value analysis method allows for incremental changes in the levelized cost of electricity (LCOE) to be determined between a baseline plant and a modified plant. CAST incorporated thermodynamic cycle analyses and component sizing with economic analysis to provide LCOE results. The model used EPRI's "Next Generation Geothermal Power Plants"¹⁰ analysis as the reference for establishing both performance and cost projections.

CAST was used to determine the optimum working fluid, based on the lowest LCOE, for a 50-MW plant with air-cooled condensation situated at four typical resources. The resource temperatures considered in this work were:

- 129°C (265°F), similar to the Thermo Hot Springs resource in Utah and referred to as RE-1;
- 149°C (300°F), similar to the Raft River resource in Idaho and referred to as RE-2;
- 166°C (330°F), similar to the Vale resource in Oregon and referred to as RE-3; and
- 191°C (375°F), similar to the Surprise Valley resource in California and referred to as RE-4.

The design condenser inlet air temperature was 10°C (50°F) at all resources. Injection temperature limits as functions of the resource temperature were imposed to prevent silica precipitation.

Emphasis was placed on evaluating the benefits of using mixed working fluids instead of pure fluids on LCOE.⁹⁶ The fluids studied were binary mixtures of propane (C₃) and isopentane (iC₅), and isobutane (iC₄) and hexane (C₇). These were identified in earlier studies as promising mixtures. The base case plant for each resource used a commercial-grade isobutane working fluid.

Figure 30 shows the results for the analysis of the 149°C (300°F) resource (RE-2) for the fluids evaluated. The base case plant had a second law efficiency of 30.6 percent, geofluid effectiveness of 4.04 watt-hours per pound (W/mgeo), and LCOE of 0.079 \$/kWh. The results from the CAST program showed that the plant with the lowest LCOE used a mixture of 93 percent propane-7 percent isopentane. This plant had a second law efficiency of 39.1 percent, geofluid effectiveness of 5.17 Watts per meter (W/m), and LCOE of 0.0700 \$/kWh, 11 percent lower than the base case.

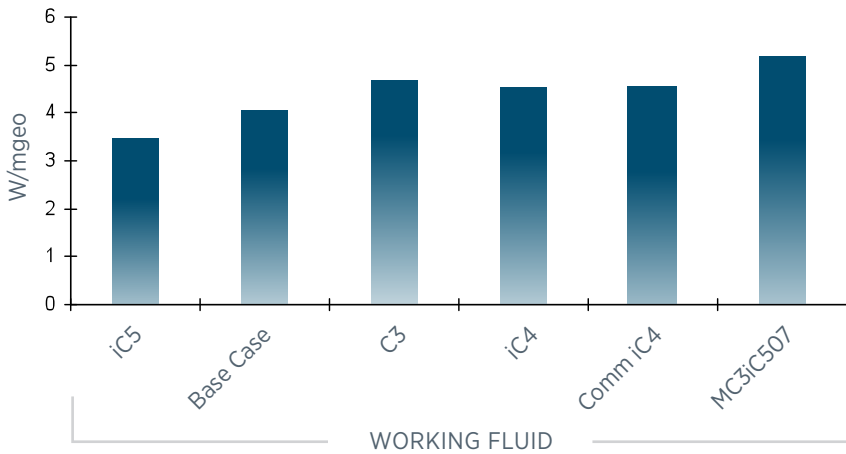


Figure 30. Effect of working fluids on binary plant performance and levelized cost of energy

The LCOEs for the best plant and base case at each resource temperature are shown in Figure 31. The LCOEs of three mixtures are also given at each resource temperature. The highest potential for LCOE reduction occurred at the lowest resource temperature. Two observations could be made relative to the economically optimum working fluids: 1) supercritical cycles were demonstrated to have lower LCOEs, and 2) when all cycles were supercritical, isobutane mixtures tended to deliver lower LCOEs. The commercial isobutane showed potential for LCOE reduction when the base case, which also used isobutane, was optimized for each resource.

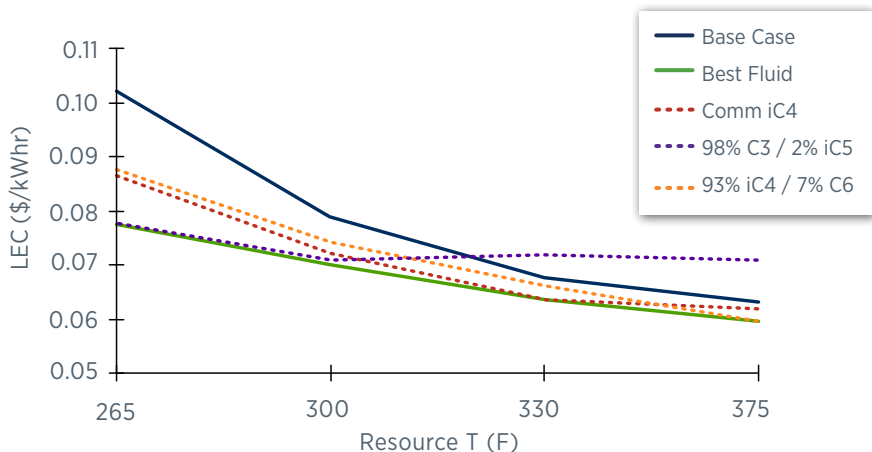


Figure 31. Summary of projected improvements in LCOE with optimized working fluids, \$1997

AMMONIA-WATER BINARY CYCLE WITH A HEAT-PUMP CONDENSER

NREL evaluated the use of an absorption heat pump in an air-cooled binary plant using an ammonia-water working fluid to mitigate the reduction in an air-cooled plant output that occurs at elevated ambient temperatures.⁹⁷ Because much of the performance information on the Kalina family of power cycles was proprietary, NREL evaluated the Maloney-Robertson (MR) cycle using the ammonia-water mixture. A schematic diagram of the MR cycle is shown in Figure 32. The MR cycle differs from a conventional binary cycle in that the working fluid is not completely vaporized in the geothermal heat exchangers. The liquid not vaporized is more concentrated in the heavier mixture components. This hot liquid is separated from the vapor and used to preheat the working fluid before entering the geothermal heat exchangers. The cooled liquid leaving the recuperators is then mixed with the turbine exhaust to reduce the condenser pressure and increase turbine output. This cycle provides additional design flexibility, that is, the concentration of the working fluid or quality of the mixture exiting the evaporator can be varied.

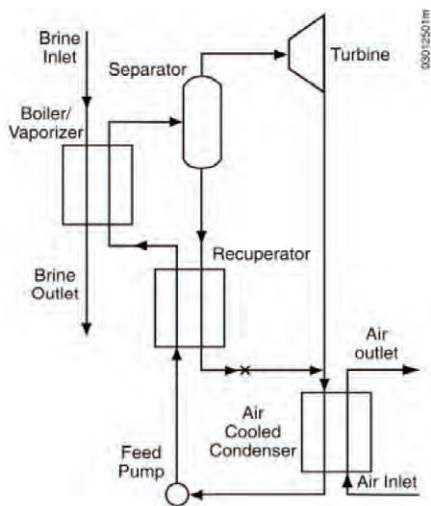


Figure 32. Schematic of Maloney-Robertson cycle

Cycle analysis considered the performance of a 1-MW plant using air-cooled condensers. The analysis considered ambient temperatures between a design value of 10°C (50°F) and an upper value of 38°C (100°F) for each of the two design resource temperatures—121°C (250°F) and 149°C (300°F). The cycle was modeled to establish the vaporizer pressure, vapor quality, and working fluid concentration that provided the optimal performance at the design ambient condition of 10°C (50°F). For the 149°C (300°F) resource, this cycle produced an optimal brine effectiveness of 3.87 W/m. If the ambient temperature rose to 38°C (100°F), the performance of this plant decreased to 2.00 W/m.

Investigators sought to offset the effect of the higher air temperature by using a single-stage absorption heat pump to augment the heat rejection system. This system would be installed downstream of the plant's air-cooled condenser, where any remaining vapor in the working fluid is condensed leaving the condenser. The energy source for the absorption system is excess brine. The study indicated that plant output could be increased by approximately 20 percent at the higher ambient temperature using excess brine flow. The excess flow required to produce this increase in power was approximately 29 percent of the design plant flow. With the 121°C (250°F) resource, a 26 percent excess brine flow produced an additional 13 percent increase in power.

PURE AMMONIA WORKING FLUID IN A LOW-TEMPERATURE BINARY CYCLE PLANT

Due to superior heat transfer performance, lower specific volume (i.e., smaller turbines and vapor piping), and higher sonic velocity, ammonia could provide a cost advantage over the typically used hydrocarbon working fluids. NREL performed a study that optimized the binary cycle for both ammonia and isobutane at different resource temperatures.⁹⁸ The study examined cycles that were both water- and air-cooled, with and without recuperators. The model used predicted-cycle, performance-sized individual components, and it inferred subsequent component costs. The cycles were evaluated with fixed ambient conditions—7°C (45°F) for air-cooled condensers, and 2.8°C (37°F) wet bulb temperature for water-cooled scenarios. A lower limit of 2.8°C (5.0°F) was placed on the heat exchanger pinch points. A minimum plant outlet temperature constraint of 66°C (150°F) was placed on all scenarios.

Three resource temperatures were considered: 166°C (330°F), 138°C (280°F), and 110°C (230°F). For each resource temperature, system parameters were varied until the net annual plant revenue was maximized. The results for the air-cooled and water-cooled plants are summarized in Table 3. These results are without recuperation.

Table 3. Air-cooled plants compared to water-cooled plants

AIR-COOLED:	Resource Temperature (°F)					
	330°		280°		230°	
Working Fluid	Isobutane	Ammonia	Isobutane	Ammonia	Isobutane	Ammonia
Inlet Pressure (psia)	515.0	761.0	285.8	564.9	150.8	410.3
Condenser Pressure (psia)	58.3	160.8	54.0	154.2	50.0	150.8
Brine Pinch (F)	14.5	5.8	6.0	5.2	19.0	16.1
Condenser Pinch (F)	15.6	11.9	14.4	11.8	13.0	12.5
Brine Outlet Temp (F)	150.0	162.0	158.2	151.9	150.0	150.5
Plant Cost (\$M)	\$35.8	\$29.2	\$25.5	\$20.6	\$17.6	\$10.9
Net Power (MW)	18.0	15.5	9.5	9.2	3.6	3.5
Specific Cost (\$/kW)	\$1,991	\$1,886	\$2,674	\$2,241	\$4,923	\$3,110
Thermal Efficiency (%)	13.0	12.0	10.3	11.8	5.9	5.8
Brine Effectiveness (kW/1,000lb/hr)	7.04	6.06	3.73	3.58	1.40	1.37
Net Cash Flow (\$K/yr)	\$3,336	\$3,076	\$939	\$1,407	-\$670	\$151

WATER-COOLED:	Resource Temperature (°F)					
	330°		280°		230°	
Working Fluid	Isobutane	Ammonia	Isobutane	Ammonia	Isobutane	Ammonia
Inlet Pressure (psia)	515.0	731.2	288.3	576.8	151.2	411.5
Condenser Pressure (psia)	49.0	140.0	49.0	140.0	49.0	140.0
Brine Pinch (F)	17.0	5.0	6.8	5.0	19.2	15.8
Condenser Pinch (F)	13.2	9.0	13.1	8.8	13.0	8.8
Brine Outlet Temp (F)	150.0	155.6	158.2	151.5	150.0	150.0
Plant Cost (\$M)	\$31.6	\$26.8	\$22.2	\$18.1	\$14.7	\$9.9
Net Power (MW)	19.9	17.7	10.6	10.4	4.0	4.2
Specific Cost (\$/kW)	\$1,590	\$1,515	\$2,106	\$1,728	\$3,676	\$2,355
Thermal Efficiency (%)	14.3	13.2	11.4	10.7	6.6	7.0
Brine Effectiveness (kW/1,000lb/hr)	7.77	6.92	4.13	4.08	1.56	1.65
Net Cash Flow (\$K/yr)	\$4,694	\$4,354	\$1,805	\$2,281	-\$117	\$584

At the highest resource temperature, the binary plant using isobutane working fluid had higher net annual revenues. However, at the lower resource temperatures, the plant using the ammonia working fluid produced a higher annual net cash flow. Recuperation was found to increase the net annual revenue for the isobutane plant for both the 110°C (230°F) and 166°C (330°F) resources that used both air- and water-cooling. It was also beneficial for the air-cooled ammonia plant using the lower 110°C (230°F) resource. Minimal benefit was found using recuperators with ammonia in the other scenarios considered. Results suggested that due to its impact on reducing condenser and turbine size, ammonia should be considered for lower temperature resources.

TRILATERAL CYCLE

The trilateral cycle is a simple thermodynamic cycle that can increase the performance of binary cycles. Its name is derived from its triangular shape when depicted on a temperature-entropy plot (Ts) as depicted in Figure 33. In the trilateral cycle, the working fluid is heated with the geothermal fluid but never vaporized. The nearly parallel curves for the cooling of the geothermal fluid and the heating of the working fluid reduce the irreversibility in the heat addition process. The high pressure liquid leaving the heater is subsequently expanded in a turbine (or total flow device) that drives an electrical generator. As the liquid expands in the turbine, it enters and never exits the two-phase region. The cycle's potential performance benefit is contingent upon the efficiency of the turbine expander operating with two-phase flow conditions. Prior research found that turbine efficiencies were low for the two-phase expansion of water. Because refrigerant working fluids used in binary cycles have lower expansion ratios than water, it was postulated that their efficiencies would be higher.

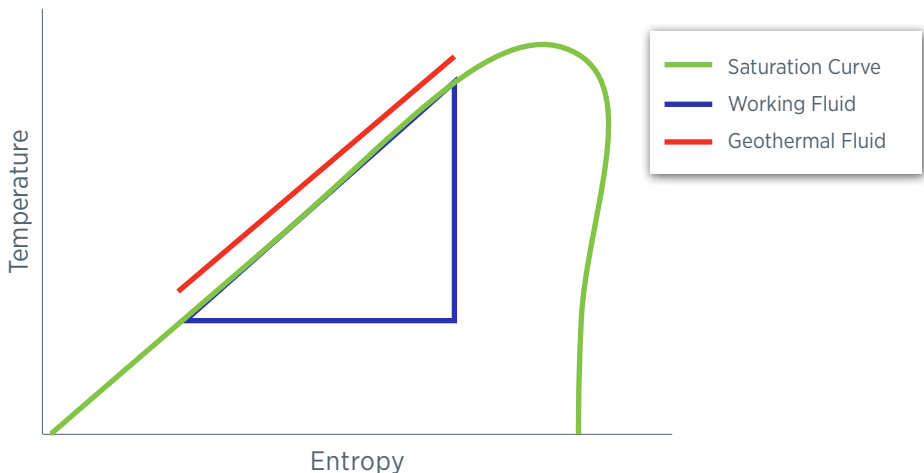


Figure 33. Temperature-entropy plot with tri-lateral cycle imposed

INL analyzed and compared the performance of the trilateral cycle to a conventional binary cycle.⁹⁹ For the same resource conditions, the trilateral cycle produced approximately 15 percent more power, assuming the same heat exchanger pinch points and rotating equipment efficiencies. However, the trilateral cycle had considerably larger heat exchangers. When performance was compared with the same heater and condenser sizes instead of equivalent pinch points, the trilateral and conventional cycles performed nearly the same. It is unlikely that a total flow expander would have efficiencies equivalent to a conventional binary cycle turbine. For the scenario with fixed heat exchanger pinch points, the trilateral cycle lost its performance advantage once its efficiency fell below approximately 90 percent of the binary cycle turbine efficiency.

The expectation that a trilateral cycle expander would achieve an efficiency approaching 90 percent of the binary cycle turbine was considered optimistic. When tested at the HCRF and operated at conditions approximating those postulated for a trilateral cycle, an impulse turbine's efficiency degraded by approximately 20 percent. In addition, any minimum constraint on the temperature of the brine leaving the plant reduced the performance benefit, suggesting that the trilateral cycle's potential for improving performance may be limited to lower temperature resources.

4.3 Findings and Conclusions

Efforts to develop technologies to cut power plant costs have been a major DOE-supported focus area. Such efforts include the development of innovative components and power cycles as described below:

- Researchers supported by DOE designed two types of heat exchangers for use with geothermal fluids with high corrosion and scaling potential whose heat transfer performance met or exceeded that of conventional heat exchangers: 1) direct contact heat exchangers and 2) fluidized bed heat exchangers. Direct contact heat exchangers were particularly effective in transferring heat between the geothermal fluid and the working fluid. Researchers developed methods for removing NCGs from geothermal and working fluids and for recovering working fluid from brine leaving the plant. However, because the geothermal fluids likely to be used in binary plants could use conventional, less expensive shell-and-tube heat exchangers research concluded. These new heat exchangers could be used in a binary system using a geothermal resource with a high potential for scaling and corrosion.
- Research to reduce the impact of air-cooled condensers on the cost and performance of binary power plants focused on improving the air-side heat transfer performance of these exchangers. Both INL's vortex generator technique and NREL's tab-fin design increased heat transfer by disrupting

boundary layers on the surfaces of a tube's fins and directing air flow into regions of low heat transfer on the fin surfaces. NREL's tab design approach was shown to provide more benefit and the INL research was terminated.

- Enhancing air-side heat transfer also increased the air-side pressure drop and fan power (for equivalent air flow). A nominal 30 percent increase in heat transfer and 10 percent increase in the friction factor were estimated to increase a typical plant's net output by 3 to 5 percent. Though the degree to which the condenser size could be reduced depends on the increase in the pressure drop, it could approach 10 percent.
- NREL worked with industry partners Super Radiator Coils and McElroy Manufacturing, Inc. to develop methods for integrating the tab-fin design into the tube-fin configurations used by industry.
- The ADCC developed by NREL has the potential to replace direct-contact condensers and surface condensers in many of the world's geothermal flash-steam and steam plants. ADCC may also be used in any industrial process in which steam is condensed.
 - ADCC technology was employed in a steam plant at The Geysers. Production efficiency was improved by 5 percent; chemical cost for hydrogen sulfide abatement was cut in half.
 - Owners could recover the cost of installing the ADCC within two years.
 - The ADCC earned an *R&D Magazine* "R&D 100" award for NREL, the Alstom Corporation, and Pacific Gas and Electric Company in 1999. In addition, researchers received the "Technology Transfer from Federal Laboratory to Industry Award" from the Colorado Technology Transfer Society for work on ADCC technology.
 - NREL licensed ADCC technology to the Alstom Corporation.
- Researchers identified power cycles that improved performance.
 - Supercritical cycles using mixed working fluids reduced irreversibilities in both the heat addition and heat rejection processes.
 - These cycles using hydrocarbon mixtures were projected to increase performance in excess of 20 percent, with corresponding reductions in power generation costs of up to 13 percent.
 - The benefits of recuperation on both performance and cost were shown when minimum temperature limits were imposed to prevent silica precipitation in the cooled geothermal fluids.

- Benefits were shown for both air- and water-cooled plants over the range of resource temperatures that would likely be used with the binary power cycle technology.
- Analysis of mixed halocarbons and ammonia and water indicated that these working fluid mixtures provided similar benefits to mixed hydrocarbons.
- Cycles were identified that could mitigate the effect of higher ambient air temperatures on the performance of air-cooled plants.
- The feasibility of achieving projected gains in performance in a water-cooled, supercritical cycle was validated during testing at the HCRF located at the DOE GTF.
 - Countercurrent flow paths, necessary for the performance improvements, were achieved in both the heat addition and heat rejection processes.
 - The integral condensation process critical to reducing irreversibilities in the heat rejection process was achieved.
 - “State-of-the-technology” design tools were confirmed to be adequate for sizing heat exchangers necessary to achieve desired process conditions and countercurrent flow paths.
 - Available methods for predicting the thermal and transport properties of the mixed hydrocarbon working fluids were found to be adequate.
 - The expansion of a vapor at a supercritical pressure through the two-phase region supported a supersaturated vapor.
 - Testing of an axial flow impulse turbine and a radial inflow reaction turbine at the HCRF indicated that their performance was not adversely impacted in the range of interest with the metastable expansions.
 - Testing indicated that turbine performance could be predicted with mixed working fluids using available methods for predicting the properties of mixtures.
- Subsequent extended testing of the modified turbine inlet conditions at an existing binary plant confirmed that operation with these expansions over an extended period did not have any adverse impact on either performance or turbine integrity. The testing revealed that these expansions could be used to increase performance at plants that had experienced a decline in resource productivity.

5.0

Power Plant Operations

Early research efforts to reduce the costs associated with operating geothermal power plants focused on addressing corrosion and scaling issues inherent in using geothermal fluids. These efforts are summarized in the previous sections. As the number of commercial power plants increased, it became apparent that additional technology improvements could decrease generation costs. For flash and steam plants, such needs included improving process monitors or instruments to provide real-time monitoring of conditions affecting plant performance, cost, or the integrity of plant components (i.e., corrosion and scaling). For binary plants, research included reducing the effects of high ambient temperatures on the performance of air-cooled binary plants and in lessening the adverse impact of NCGs in binary cycle working fluid systems on both plant output and O&M costs.

5.1 Improved Monitors

One component of a geothermal plant's O&M cost is related to the fluid's corrosion and scaling potential. In lieu of using expensive construction materials, the effects of corrosion and scaling can be mitigated by fluid handling technologies involving chemical, mechanical, or other processes. Typically, opting for lower capital costs results in increased O&M costs associated with both fluid handling technologies.

DOE supported research to develop technologies that would lower these O&M costs in both existing and future plants. Work focused primarily on developing improved monitors that would enhance the technologies associated with mitigating corrosion and scaling in various plant processes, systems, and components, and lower the associated costs.

5.1.1 Plant Process Stream Monitors

In 1997-1998, INL researchers asked steam and flash-steam plant operators to prioritize where in the plant monitoring different chemical species could have the greatest impact on O&M costs and plant performance. Plant operators identified continuous monitoring of hydrogen sulfide in the air leaving an evaporative cooling tower and in the main steam supply line as the highest priority. Operators further listed the real-time measurements of hydrogen chloride in the main steam supply line, hydrogen sulfide in the untreated noncondensable gas stream leaving the condenser, and the moisture content of steam entering the turbine as secondary priorities. While methods existed to make these measurements, they were not done on a continuous, real-time basis.

HYDROGEN SULFIDE MONITOR

Hydrogen sulfide (H_2S) comes out of solution when a geothermal fluid flashes or boils. In steam and flash-steam plants, H_2S accumulates in the condenser along with other NCGs and must eventually be removed. If there are regulatory requirements, abatement processes are used to minimize the emission of H_2S to the environment. The abatement processes require both chemicals and manpower, which add to the plant's O&M costs. Because H_2S was not measured continuously, chemicals were liberally applied to ensure regulatory compliance—further increasing costs.

INL pursued the development of continuous, on-line measurement of H_2S based upon near-infrared, tunable diode, laser spectroscopy.¹⁰⁰ The approach took advantage of diode laser devices developed for telecommunications that are compact, operate at room temperature, have modest power requirements, and whose signals can be easily propagated over standard communication-grade optical fiber. The system INL developed was self-calibrating and could store and display data on a personal computer.

In laboratory testing, a H_2S detection limit on the order of around 25 ppmv per meter of path length was readily obtainable. Testing indicated that the measurement was quite sensitive to changes in pressure but less sensitive to temperature changes. Researchers observed that the device was effective at excluding the contribution of water vapor to the signal. However, there was a marked decrease in the signal-to-noise ratio when water droplets formed from the vapor were comparable to the size of the wavelength of light.

The H_2S monitor was field tested at the Northern California Power Agency (NCPA) Unit 1 plant at The Geysers. In initial testing, the spectroscopy measurement exhibited a typical precision of approximately 25 ppmv per meter, comparable to results obtained in laboratory testing under similar conditions.

A longer test was conducted where H_2S levels (0-20 ppmv range) were measured in the treated gas stream leaving the NCPA plant's Stretford abatement system. The data collected during an eight-week run is shown in Figure 34. The periodic spikes in the data occurred during the instrument's self-calibrations. During this particular eight-week period, the spectroscopy system operated unattended with no operator intervention.

The device's detection sensitivity was found to be adequate for process streams with H_2S levels of more than approximately 1 ppmv. The diode devices that would provide the sensitivity required for measurements of emissions from the cooling tower—where the required detection limits could be in the 0.1- to 5-parts per billion per volume (ppbv) range—were not available during these investigations.

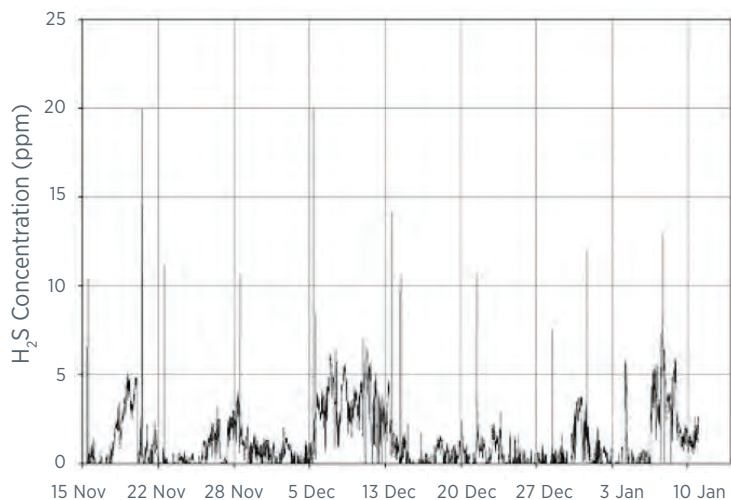


Figure 34. Hydrogen sulfide measurements during extended test at the Northern California Power Agency Unit 1 plant at The Geysers, California

HYDROGEN CHLORIDE MONITOR

Steam plant operators were concerned with hydrogen chloride (HCl) because it goes into solution with the first steam condensate that is formed, and it can cause significant damage to surfaces it contacts including the plant turbine. To mitigate the potential for damage, operators may “wash” the production steam before it enters the plant to minimize HCl’s adverse effects. While effective in reducing corrosion potential, “washing” de-superheats the steam, lowers its enthalpy content, and reduces the amount of power that can be generated. In addition, excessive water use can result in erosion damage from droplets entrained in the steam.

INL investigators developed a way to continually monitor the presence of HCl in steam, allowing the washing process to be optimized and de-superheating minimized.¹⁰¹ The monitoring methodology is based on the same near-infrared, tunable diode, laser spectroscopy used for on-line monitoring of H₂S. Because HCl and H₂S have different targeted absorption band wave lengths, they require different laser diodes. Otherwise the monitor is essentially the same for both gases.

During laboratory testing of HCl in nitrogen, a detection limit of approximately 1 ppmv per meter was observed in measurements made at atmospheric pressure. Detection sensitivity was primarily limited by etalon effects¹⁰² and laser feedback noise at low concentrations. Testing the measurement response to changes in pressure and temperature indicated higher sensitivity to pressure, though not as significant as that observed during the H₂S testing.

Testing was then performed in a controlled, high-temperature, steam environment in collaboration with Thermochem, Inc. at its laboratory in Santa Rosa, California. The testing determined that the spectroscopic line broadening of nearby water vapor lines, which occurred at elevated pressures and temperatures, interfered with the absorption band selected for HCl detection. Researchers resolved this issue by using diode devices that operate at wavelengths that correspond to stronger absorption bands and are less susceptible to interference from other species likely to be present (e.g., water and CO₂). The remainder of the monitoring system operated as expected, indicating that the basic approach was valid.

As the cost of diode devices operating at the desired wavelengths decreases, it should be feasible to continuously measure both HCl and H₂S at costs acceptable to the geothermal industry.

STEAM QUALITY MONITOR

During the separation of liquid and steam phases in a flash-steam plant, small droplets become entrained in the saturated steam that enters the turbine. These droplets can cause scaling and erode turbine surfaces, harming turbine efficiency. A one-percentage-point decrease in turbine efficiency for a 50-MW plant can cut annual revenues by approximately \$250,000 (at 5¢/kWh). A one-week shutdown to clean, replace, or repair a turbine cuts revenue by more than \$400,000 for a 50-MW plant.

INL researchers designed a steam quality monitor that would provide a continuous, sensitive measurement of the amount of moisture (liquid) present in the steam.¹⁰³ The monitor was developed based upon the selective absorption of infrared radiation, which, though not new, had not been used due to its cost and complexity. Researchers addressed these issues by incorporating semiconductor emitter and detector techniques that are compact, relatively inexpensive, and compatible with standard low-loss optical fiber technology.

Laboratory investigations

During steam quality monitor laboratory testing, changes in quality on the order of 0.05 percent could be detected over the 96 to 100-percent quality range. In these tests, laser diode devices performed better than broadband light emitting diode devices, and had the added advantages of being cheaper and easier to obtain.

Initial field tests

The INL steam quality monitor was first field tested at the Bonnett Geothermal Plant in Utah. Measurements were made using a bypass stream at four different locations in the flash plant. Results indicated that the optical technique was quite sensitive to changes in steam quality; changes in quality on the order of

0.03 percent could be detected. The device responded faster and operated over a wider range of moisture than the throttling calorimeter. No interferences from other gas constituents were observed with the diodes tested.

Extended field test

The instrument was subsequently modified for an extended test at the Brady Geothermal Power Plant near Fallon, Nevada. In this test, optical probes were installed in the turbine inlet piping, with optical signals transmitted via fiber optics to and from the probes. Figure 35 is a photo of instrumentation electronics and the probes installed in a sample section of pipe.

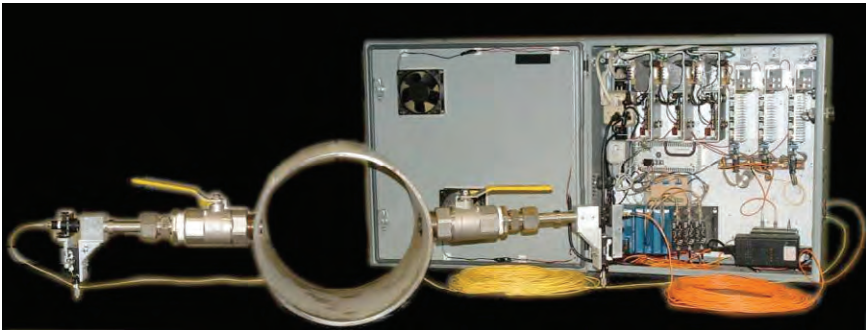


Figure 35. Optical steam quality monitor probes and electronics

Periodic water washing to reduce scale accumulation on the turbine's internal surfaces provided a known perturbation of the moisture content of steam entering the turbine. An example of the data collected during a turbine water wash is shown in Figure 36. The data show the effect on the measurement when adding small quantities of water to the nominal 120,000 lb/hr of steam. Over the 150-day deployment, the device readily tracked small changes (approximately 0.25 percent) in moisture content. The steam quality monitor operated with minimal impact on plant operation. While there was some fouling of the window (across which the optical signals are transmitted) during extended operation, no serious maintenance issues were discovered. The optical probes were never removed for cleaning or repair over the entire deployment.

The signal amplitude decreased during the test, though it was noted that the signal recovered following a window washing. The decrease in signal was attributed to fouling of the window surface, and the recovery to cleaning the window during turbine wash. This suggested that the instrument signal could be used to indicate when washing was merited, as well as when internal components were sufficiently clean that the washing process could be terminated. This feature is one of the main reasons ThermoChem licensed the technology.

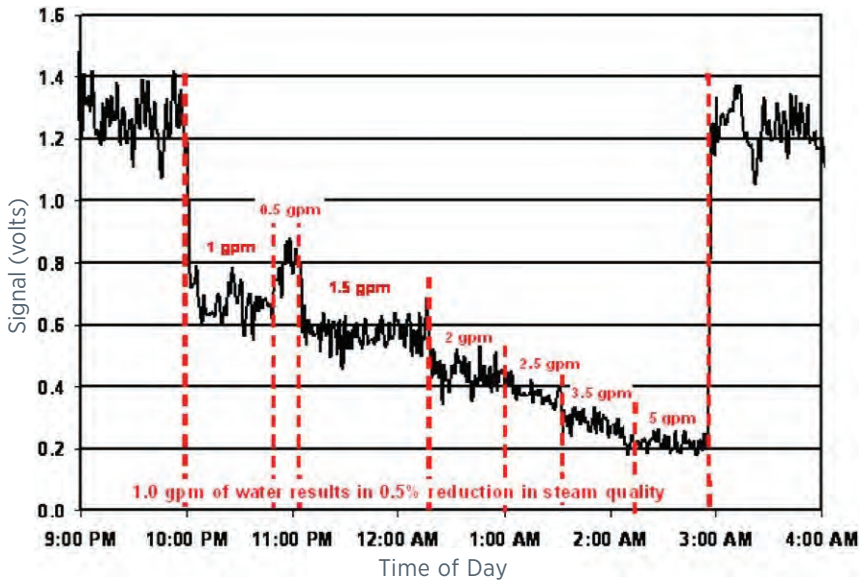


Figure 36. Steam quality monitor response to turbine water washing

PARTICULATE MONITORING

During development of the steam quality monitor, facility operators and industry representatives expressed the need for an instrument to detect the presence of particulates in steam. INL had previously examined the potential use of laser-induced breakdown detection (LIBD) to identify the precipitation of solids in geothermal brines used in binary conversion systems. LIBD is based on the spectroscopic analysis of the plasma produced when a high-power laser pulses onto a particle in a process stream and monitoring the resulting acoustic signals. While the LIBD technique provides information on the particle's elemental composition, size, and concentration, it is relatively complex and expensive to field and operate.

Researchers subsequently assessed the feasibility of modifying the steam quality monitor to detect the presence of particulates in steam. Modifications included 1) adding a laser diode that is less sensitive to water and water vapor and more sensitive to scattering phenomena and 2) using new processing techniques to recover the signal. Successive laboratory experiments were hindered by excessive noise from faulty electronics making it difficult to establish a detection limit. However, results were encouraging because there were several measurement parameters that could be tuned to increase the measurement sensitivity. Research efforts were concluded in 2006 before the electronics could be replaced and testing repeated.

5.1.2 Monitoring Biological Activity

Microbial activity is an operational issue in geothermal power plants that use evaporative heat rejection systems. Steam impurities such as hydrogen sulfide, ammonia, carbon dioxide, and dissolved or entrained solids provide nutrition for microbial growth that are unique to geothermal plants. These microorganisms decrease plant performance and increase O&M costs. If left untreated, they form biofilms that decrease power output and promote corrosion of component and piping surfaces. The economic impact of microbial activity on the operation of a 50-MW plant can exceed \$500,000 per year. This is the result of lost power revenue associated with periodic cleaning the condenser and cooling tower, eventual replacement of failed tubes, and the effects of condenser fouling on turbine exhaust pressure. Yet few geothermal plants have monitoring programs to detect microbial growth problems. The timing of chemical treatments is set by either vendors with an interest in sales or a visual indication of film formation or degradation in plant performance.¹⁰⁴

INL conducted a multi-year research study to characterize and evaluate microbiological activity in geothermal power plant cooling systems at dry steam and flash-steam geothermal plants in California, Utah, and Nevada. Principal field evaluations were performed at The Geysers Geothermal Field in Northern California and the Bonnett Geothermal Plant in Utah.

Researchers used a variety of techniques to characterize and monitor the microbial populations in the geothermal facilities.¹⁰⁵ Investigations also examined different methods to increase the frequency and quality of microbial activity monitoring, enabling plant operators to be more proactive in their application of biocides. The techniques included:

- Periodic examination of the surfaces of metal coupons after removal from plant cooling systems (used at The Geysers and the Bonnett plant).
- The most probable number (MPN) method analyzes collected samples that have been combined with selective growth media to promote the activity of specific types of microbes. The MPN technique was used in the sampling at a number of plants, including six different facilities at The Geysers. Seasonal results for sulfur-reducing and acid-forming bacteria are shown in Figure 37.

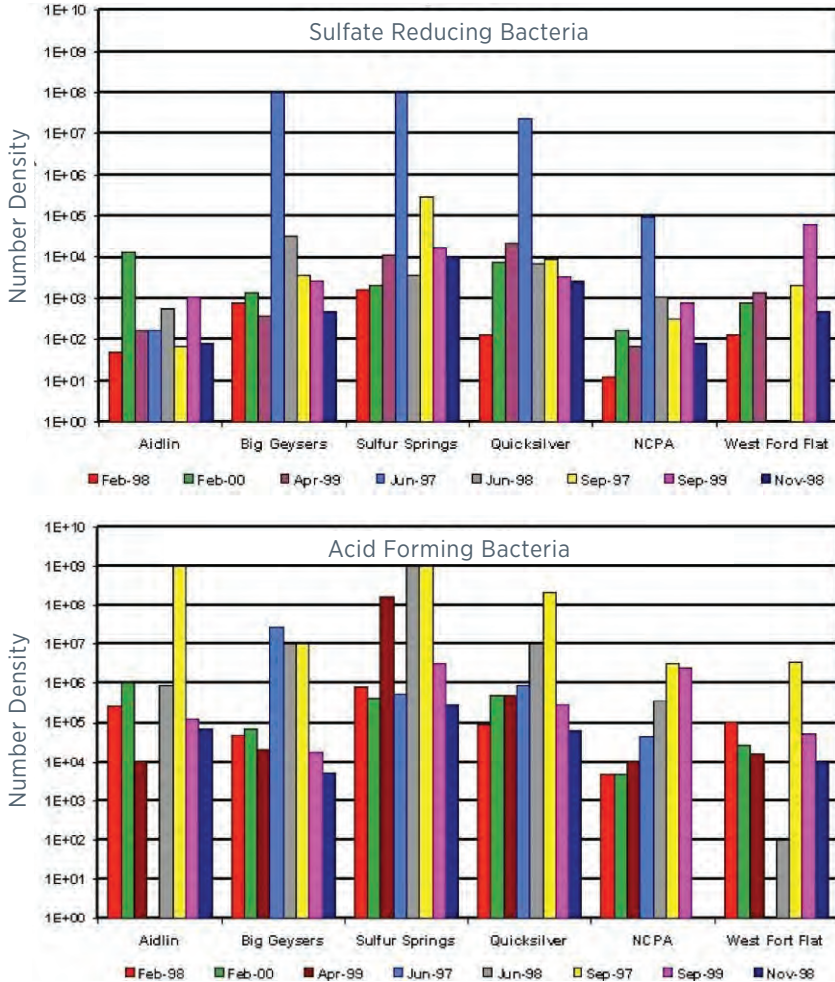


Figure 37. Most probable number results from sampling at The Geysers, California

- Total organic carbon (TOC) was found to have a direct correlation with microbial density. Water chemistry analysis also suggested an inverse relationship between sulfate concentrations and biological growth.
- Different electrochemical measurements were evaluated. The BioGEORGE™ Biofilm Activity Monitoring System was the most promising. Its measurement is based on the detection of a biofilm that preferentially grows on an electrode that is polarized daily to a preset direct current (DC) potential. (That is, the polarization cycle had been shown to encourage biological growth). BioGEORGE™ was first tested at the Bonnett plant for 18 months and later at the Aidlin plant at The Geysers for 8 months. Recorded data from the Bonnett plant are shown in Figure 38 along with pertinent plant occurrences.

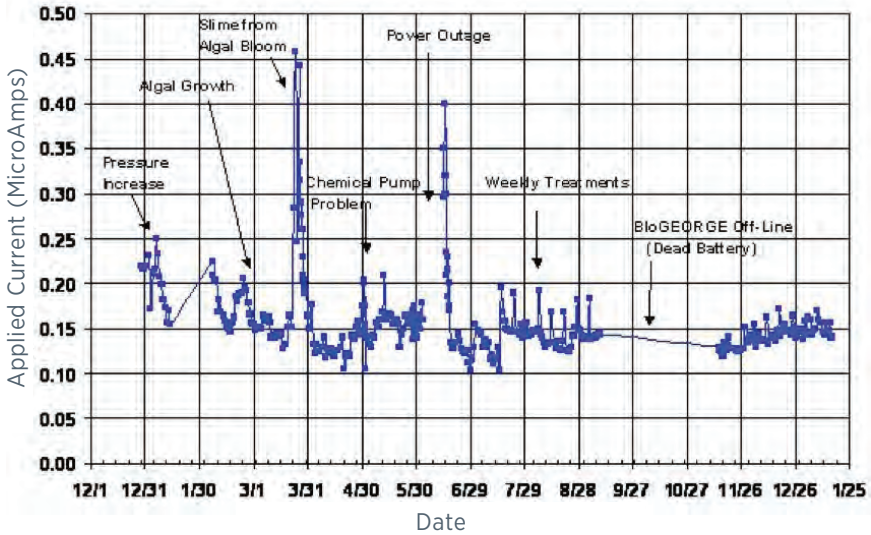


Figure 38. BloGEORGE™ data collected during testing at the Bonnett plant, Utah (December 2000 to January 2002)

- Adenosine triphosphate (ATP) is a high-energy molecule generated by living cells to perform metabolic functions. Analysis for ATP provides a means of estimating the concentration of living biomass in a sample. In sampling at The Geysers, ATP levels mirrored visual observations (cell counts) of microbial density.
- Phospholipid fatty acid (PLFA) analysis is a quantitative means of measuring viable microbial biomass, the composition of that biomass community, and the nutritional status. When used with a complementary deoxyribonucleic acid (DNA) analysis, such as denaturing gradient gel electrophoresis (DGGE), biomass composition can be determined down to the species level. PLFA analyses of samples at The Geysers compared favorably with MPN analyses.
- The use of fluorescent in situ hybridization (FISH) tags to track specific organisms and their activities was also investigated. A complementary strand of nucleic acid is constructed and tagged with a fluorescent compound to increase the ability to detect the targeted organism's presence. Research validated the ability to distinguish targeted bacteria from the general population.

An analysis compared the expected costs associated with each of the above biological measurement techniques.¹⁰⁶ Costs and mode of operation are summarized in Table 4. The estimate assumes that two samples are collected and processed weekly along with the required calibration standards and any replicate samples (if necessary) for one year. Facility labor was estimated at \$50 per hour. It was assumed that the DGGE/PLFA analyses are performed via a subcontract to a commercial laboratory specializing in these measurements; those costs are based on INL's experiences.

Table 4. First year cost comparison of biological measurement methods

Method	Operational Mode	Equipment Costs	Materials Costs	Analysis Costs	Total Costs
Coupons	Sample		\$2,400	\$2,600	\$ 5,000
Electrochemical	Continuous	\$ 8,000		\$1,300	\$ 9,300
ATP	Sample	\$ 2,000	\$6,800	\$5,200	\$14,000
MPN	Sample		\$6,700	\$7,800	\$14,500
TOC	Sample	\$24,000	\$ 350	\$6,500	\$30,850
DGGE/PLFA	Sample		\$1,000	\$55,000	\$56,000

Only the electrochemical method, BloGEORGE™, was found to be capable of providing a continuous, real-time indication of microbial activity. Coupon deployment had lower first-year costs but only provided indication of microbial presence “after-the-fact.” While the other evaluated methods had higher costs and did not provide continuous monitoring, they did provide more detailed information regarding the make-up of microbial populations. A well-designed monitoring system would likely incorporate a combination of these techniques to meet the specific needs of a facility.

BIOREACTORS ANALYSIS

Limited investigations were also conducted to identify potential benefits of microbes in the plant cooling systems and to better understand both their nutritional needs and life cycles. Not all the microbes adversely affect the plant; some contribute to the oxidation of hydrogen sulfide, thus reducing abatement costs.¹⁰⁷ INL’s microbial research activities ended in 2004.

5.1.3 Non-Destructive Testing of Corrosion/Erosion in Piping Systems

BNL’s Non-Destructive Testing (NDT) program evaluated the feasibility of using long-range NDT methods to detect corrosion and erosion-corrosion damage to geothermal piping.¹⁰⁸ Industry typically used measurements that only evaluated the pipe condition at the measurement point; damage in adjacent areas went undetected. Due to their cost, these tests were impractical for assessing the condition of extensive lengths of piping. Their use was limited to the specific points in piping that were susceptible to corrosion and erosion-corrosion. BNL’s research sought to develop an on-line, real-time NDT method to detect localized corrosion that could be used to monitor significant lengths of piping from a single location.

Two long-range NDT methods were selected for investigation on the basis of their potential improved performance, reliability, and economics: dynamic response and long-range guided wave methods. The former was based on principles of structural dynamics; the latter was based on elastic wave propagation theory. Initial efforts focused on the more developed long-range guided wave propagation. Oil and gas,

chemical, and other industries have successfully used this method to screen piping systems for corrosion and erosion problems. The commercial system evaluated used piezoelectric transducers that propagated waves in both directions down the pipe. Under ideal conditions, the system had a range of up to 175 meters and detection limits of 5 to 10 percent of the wall thickness.

BNL solicited input from industry on specific needs and priorities for an NDT system and information on extending the operating life of piping and equipment. Measurements of insulated piping, operation at elevated temperatures, detection of pitting corrosion, and accuracy were identified as being important attributes of an NDT method. Industry also expressed interest in the ability to measure scale thickness and to develop methods for in situ repair and strengthening of corroded pipe. As part of this work, assessments were made on alternative methods for in situ repair that would be more effective than the welded patches commonly used. Composite wraps were found to have the greatest potential for repair and strengthening of geothermal piping. Work was suspended in 2003.

5.2 Noncondensable Gas Removal System for Binary Plants

NCGs are typically not associated with binary power cycle working fluid systems. Residual air is present, however, following the initial filling of the plant with fluid. Routine repair or replacement of components can also introduce residual air. Once present, NCGs' impact on the binary cycle condenser is similar to that in a steam plant condenser. The partial pressure of NCGs increases the total condenser pressure. Additionally, NCGs impede the condensation process, further increasing condenser pressure and decreasing turbine output. If NCG accumulation becomes significant, operators will vent the accumulated gas in binary condensers to reduce the magnitude of the partial pressure. Because a considerable amount of NCGs can be in solution in the working fluid, venting over a long period may be required to reduce partial pressure.

Even though most plants have systems that recover a portion of the working fluid that is vented along with NCGs, the amount of working fluid lost precludes continuous venting of the condenser. To minimize this loss, operators initiate venting only after the level of NCGs has reached a maximum threshold—terminating venting after a “minimum” level is reached. An example of periodic venting from a plant where NCGs are continually introduced is shown in Figure 39. The gradual buildup of NCGs is clearly illustrated, followed by a sharp decline during the venting and the subsequent buildup of gases. On average, the plant was operated with an NCG partial pressure of approximately 4.5 psi. Because approximately 1 percent of plant output was lost per 1 psi increase in condenser pressure, maintaining a constant 1 psi partial pressure increased plant output by approximately 3.5 percent.

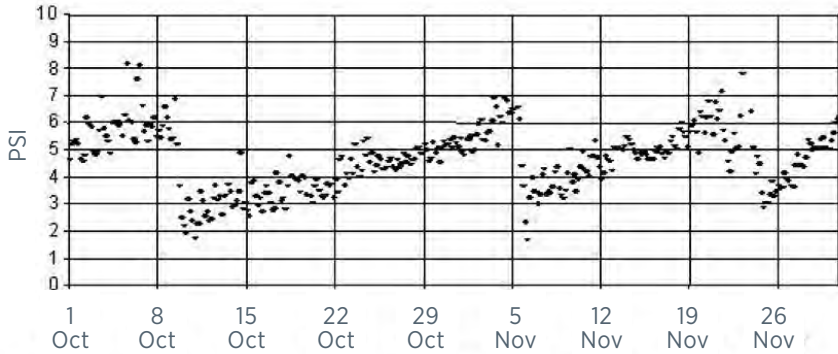


Figure 39. Accumulation of noncondensable gases in commercial binary plant

INL developed a system that used membrane separation technology to continuously remove NCGs from the working fluid system.¹⁰⁹ The membranes preferentially allowed one of the vent stream components to permeate while retaining the remaining components. INL worked with Membrane Technology and Research, Inc. to identify membranes suitable for separating air from isobutane and isopentane. The system also contained phase separation vessels, a compressor, and an air-cooled condenser. Working fluid condensate was collected within the system and returned to the plant's working fluid system. All of the system components were mounted on a 7 x 10 x 7-foot skid with power requirements less than 10 horsepower (hp). A photo of the system is shown in Figure 40. The membrane modules are in the horizontal vessels located in the foreground.

The removal system was designed to operate at two different facilities, one using an isopentane working fluid and the other using isobutane. Initial testing was performed at the Steamboat I facility south of Reno, Nevada, an air-cooled plant using isopentane. Figure 41 illustrates the impact that operation of the NCG removal system had on condenser pressure over five days of continuous operation, plotting air content in the condenser (mass fraction) as a function of time. The indicated change in air concentration in the condenser vapor space corresponded to a change in the NCG partial pressure from approximately 3.7 psi to approximately 0.4 psi. During this operating period, the amount of hydrocarbons in the NCG gas stream leaving the removal skid and being vented to the ambient ranged from 1 to 1.5 percent—about one-twentieth of the loss rate from a conventional vent and working fluid recovery system.¹¹⁰ Continuous operation of the removal system at the Steamboat I facility was hindered by the unreliable operation of the condensate return pump.

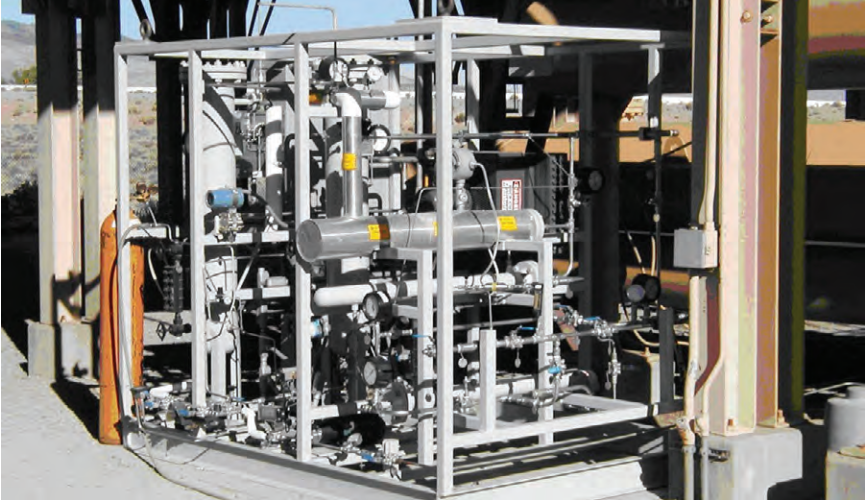


Figure 40. Gas membrane separation system to continuously remove noncondensable gases from a binary working fluid system

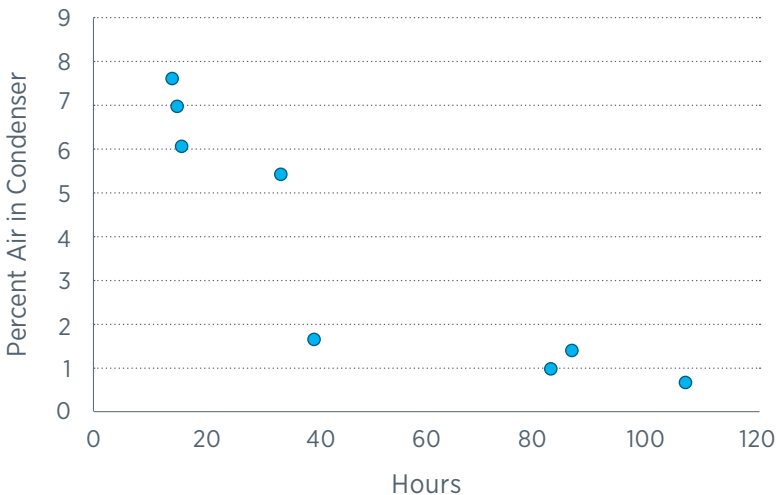


Figure 41. Reduction in noncondensable gases in Steamboat I, Nevada condenser

The NCG removal system was subsequently moved to Mammoth Pacific Geothermal, LP's MPI facility near Mammoth Lakes, California—an air-cooled binary plant using isobutane. Operation at the Mammoth facility was impacted by a number of factors, including atypical condenser vent rates (i.e., high air introduction rates) and higher levels of water in the condenser vent stream. (The presence of water was attributed to water vapor in the air being introduced.)

Considerable effort was expended at this location in getting the “system” to operate without operator intervention. These efforts included facilitating the return of working fluid to the plant, as well as heat tracing portions of the condensate piping to prevent freezing of accumulated water. Due to abnormal air introduction rates, working fluid losses from the system at Mammoth exceeded those at Steamboat, but they were significantly less than those experienced prior to the system’s installation.

5.3 Off-Design Operation of Air-Cooled Binary Plants

Lower temperature, liquid-dominated resources are frequently located in regions with insufficient water to provide make-up to evaporative heat rejection systems. These plants subsequently reject heat sensibly to the ambient in air-cooled condensers. Typically, these plants are designed to produce their rated capacity (design output) at the average annual air temperature for their location. Consequently, the ambient temperature exceeds the design temperature several times a year.

Because geothermal is a relatively low-temperature energy source, outputs from geothermal power plants are sensitive to the temperature at which heat is rejected. This is particularly true of air-cooled binary plants. For example, for a 149°C (300°F) resource, a 0.6°C (1.0°F) increase in air temperature decreases available energy by approximately 0.8 percent. (Available energy represents the ideal work that could be done by a conversion system operating between the resource and ambient temperatures.) Sensitivity to ambient temperature increases as resource temperature decreases. Each day, geothermal power plants experience changing air temperatures and the resulting effects on performance. Further, over time plants typically experience a decline in resource productivity due to declining temperature and flow rates. Decreases in resource temperature reduce available energy, analogous to the impact of increasing air temperature. While ambient air temperature changes are cyclic, a decline in resource productivity is generally irreversible.

5.3.1 Mitigating Effects of Off-Design Operation

INL examined the impact of off-design operation on an air-cooled binary power plant in order to evaluate different schemes’ ability to minimize those impacts.¹¹¹ (An “off-design” plant operates at conditions [e.g., geothermal flow, pressure, temperature, and design ambient temperature] that differ from those for which it was designed.) Researchers developed a power plant model that simulated performance of various components in an air-cooled plant. The model simulated the effect of off-design conditions on the performance of fixed-size turbines and pumps, as well as the performance of heat exchangers and condensers having fixed heat transfer areas. Pressure drops in the modeled plant also varied with flow rates. The model was developed using operating data and equipment specifications for an existing plant utilizing an isobutane working fluid. Data from this plant at off-design conditions was used to “calibrate” the model.

Figure 42 illustrates how ambient conditions affect the performance of an air-cooled binary plant operating at design conditions. These results show how the available energy is dissipated in the plant. The “ P_{net} ” curve is the second law efficiency for the plant. The remaining curves reflect the degree to which the effluent stream of available energy or component irreversibility adversely affects this conversion efficiency. At a given air temperature, the sum of P_{net} (the available energy of the air and geothermal fluid streams leaving the plant) and the component irreversibilities equals 100 percent. The individual curves for the available energy of the effluent streams and the component irreversibility show how each impacts plant performance as a function of the ambient temperature. If a curve increases with increasing ambient temperature, the parameter associated with that curve has an adverse impact on conversion efficiency with increasing air temperature.

Figure 42 shows that, in addition to the unavoidable decrease in the available energy that occurs with increasing air temperature, the efficiency at which the plant converts this energy to power (“ P_{net} ”) also decreases. Strategies to reduce this adverse impact on conversion efficiency focused on those with the highest impact and increase with air temperature.

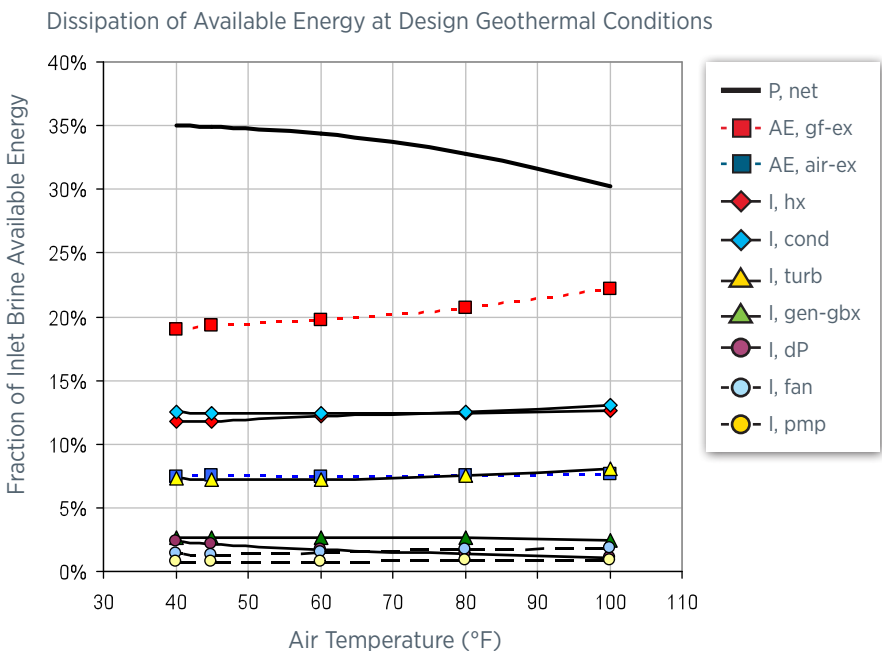


Figure 42. The effect of ambient conditions on the performance of an air-cooled binary plant operating at its design geothermal conditions

AE: the available energy of the fluid stream exiting the plant; **gf:** geothermal fluid; **I:** the component or system irreversibility; **hx:** geothermal heat exchangers; **cond:** air cooled condenser; **turb:** turbine; **gen-gbx:** generator and gearbox; **DP:** friction losses; **fan:** condenser fan; and **pmp:** working fluid pump.

Similar analyses conducted at off-design geothermal conditions found that at the design ambient temperature, the conversion efficiency increased with a decline in the resource flow rate. This increase occurs because smaller approach temperatures are being achieved in the fixed-sized heat exchangers because less heat is being added and rejected. Because the temperature differences are smaller, the associated irreversibilities are decreased and the second law efficiency increases. This analysis assumed the turbine had a variable nozzle geometry that allowed the inlet pressure to be adjusted (an efficiency penalty was imposed based on the degree to which flow was throttled). With a decline in the resource temperature, conversion efficiency decreased even though less heat was added and rejected. This occurs because with a lower geothermal temperature, the turbine inlet pressure that provides optimal power output decreases. While this also occurs with a lower geothermal fluid flow rate, the extent to which the turbine inlet pressure must be decreased is greater with a decreasing fluid temperature. The lower turbine inlet pressure tends to increase irreversibility associated with heat addition (because temperature differences are larger), friction losses (flow throttling with control valves), and pumping. These factors, combined with lower turbine efficiencies (lower inlet pressure), produce decreased conversion efficiencies. In all off-design resource scenarios, plant performance (second law efficiency) declined with increasing air temperature.

To increase plant power production at any given ambient and resource conditions, dissipation of available energy from one or more of these consumers must be reduced. Researchers considered several approaches to reduce these irreversibilities and increase performance. The most promising concepts to mitigate the impact of higher air temperatures were evaporative pre-cooling the air and increasing the heat exchanger and condenser surface areas. In the case of declining resource productivity, options to improve performance included 1) using variable frequency drives (VFD) on pump and fan motors and 2) removing the constraint on the turbine inlet superheat. Projected benefits from these options are shown in Table 5 for two different geothermal resource scenarios.

Table 5. The impact on plant power output projected for two geothermal resource scenarios

	DESIGN GEOTHERMAL CONDITIONS			
	Annual Power (kW-h)	May-Sept [kW-h]	Annual Increase	Summer Increase
Reference Plant	127,506,584	47,633,536	-	-
Increase HX UA 25%	131,913,392	49,436,071	3.5%	3.8%
Increase Cond UA 25%	131,529,156	49,282,495	3.2%	3.5%
Pre-Cooling Air	131,577,608	51,704,561	3.2%	8.5%
Minimize Superheat	-	-	-	-
VFDs – Pump and Fans	-	-	-	-

	OFF-DESIGN: 20°F DECREASE IN GEOTHERMAL FLUID TEMP.			
	Annual Power (kW-h]	May-Sept [kW-h]	Annual Increase	Summer Increase
Reference Plant	102,640,930	37,782,607	-	-
Increase HX UA 25%	109,842,833	40,184,576	5.6%	5.0%
Increase Cond UA 25%	108,533,410	39,643,183	4.6%	3.9%
Pre-Cooling Air	106,866,378	42,008,055	3.3%	8.9%
Minimize Superheat	104,392,687	38,260,626	1.4%	1.0%
VFDs – Pump and Fans	107,729,675	39,706,902	4.0%	4.0%

The power output values shown were derived using model results and hourly temperature data from Reno, Nevada in 1995. If there is a premium for power generated during the summer months, evaporative pre-cooling of the air may significantly increase revenues during that period. The projections shown in the table assumed that air was pre-cooled continuously from May through September. If water availability limited air pre-cooling to only the hotter parts of the day, the benefit declined slightly.

On the basis of annual power output, increasing the size or performance of heat exchangers will have a slightly larger impact than increasing the size of air-cooled condensers. Because heat exchangers cost substantially less than air-cooled condensers, increasing heat exchanger size is preferred. Unless there is a premium associated with summer power sales, it is probable that increasing the heat exchange area would be more economically viable than pre-cooling the air—especially if pre-cooling the air increases operating costs.

Installing VFDs on pump and fan motors is a less-intrusive modification to an existing power plant, and the potential gain would be significant if a decline in resource productivity had occurred. The relative benefit from eliminating the constraint on the superheat entering the turbine is small and only results when a decline in resource productivity has occurred. There is, however, little cost associated with incorporating this concept, and the benefit would continue to increase with further decline in the resource productivity.

5.3.2 Evaporative Cooling Enhancement Methods for Air-Cooled Plants

Because air-cooled, binary plants are commonly designed for an average annual air temperature, output during periods of elevated temperatures in the summer can be substantially less than design output. On hot summer days, a plant's electric output can drop up to 50 percent from winter levels. The economic effects of reduced summer performance are exacerbated by the usually higher value of electricity in the summer.

In response to a solicitation to develop small-scale power plants, DOE made an award to develop a 1 MW binary power plant at Empire, Nevada. The proposed plant would employ air-cooling and augment summer heat rejection with evaporative cooling. NREL developed a spreadsheet model to provide a cost-and-performance comparison of the alternatives for these systems that would be immediately useful for the Empire design and also be robust enough for use by other plant designers.¹¹² The model considered four methods for using supplemental evaporative cooling to boost summer performance: 1) pre-cooling with spray nozzles, 2) pre-cooling with Munters media,¹¹³ 3) a hybrid combination of nozzles and Munters media, and 4) direct deluge cooling of the air-cooled condenser tubes.

Performance projections were based on weather data from Reno, Nevada, and pressure drop and evaporative performance data obtained from the manufacturer of the evaporative media. The cost analysis of each system included the capital costs of equipment and installations, as well as routine maintenance and ongoing costs (e.g., water consumed). Performance and cost data for each system were collected and evaluated using five key economic indicators: 1) total life-cycle cost, 2) net present value, 3) LCOE, 4) simple payback, and 5) internal rate of return.

Projected power output from the plant as a function of air temperature was based upon modeled results for the Empire plant at a resource temperature of 118°C (245°F). Output was limited at lower ambient temperatures because the plant's condenser pressure was constrained to always be above 1 atmosphere. These correlations were used to project plant output for each hour of the typical day selected for each month. It was assumed that the evaporative cooling systems would only be used from May through October and drained for the other months.

Figure 43 shows a schematic of one of the systems considered—a spray nozzle cooling system. Water droplets leaving the nozzles are projected to have diameters on the order of microns, allowing them to evaporate very quickly and effectively. In the Munters packing system, these nozzles are replaced with a wetted packing material that cools air passing through the packing. The hybrid system uses a combination of the spray nozzle and the Munters packing systems, allowing for a less-sophisticated array of spray nozzles and lower pressure drop in the packing, which is thinner. Because the quality of the water is unknown (e.g., it could be cooled geothermal fluid), these three systems minimize the contact of moisture with the condenser tube bundle. The final system considered used a deluge cooling method whereby water was pumped onto condenser tube surfaces, using reverse-osmosis to clean the water or a coating material to protect the tube and fin surfaces. For this analysis it was assumed that water suitable for cooling cost \$1 per 1,000 gallons. In order to reflect the value of electricity as a function of weather, the electricity price was varied according to the schedule used for Standard Offer 4 (SO4). Though the SO4 is no longer in use for electricity purchases, it was used in order to illustrate the time-of-generation effect with the model.

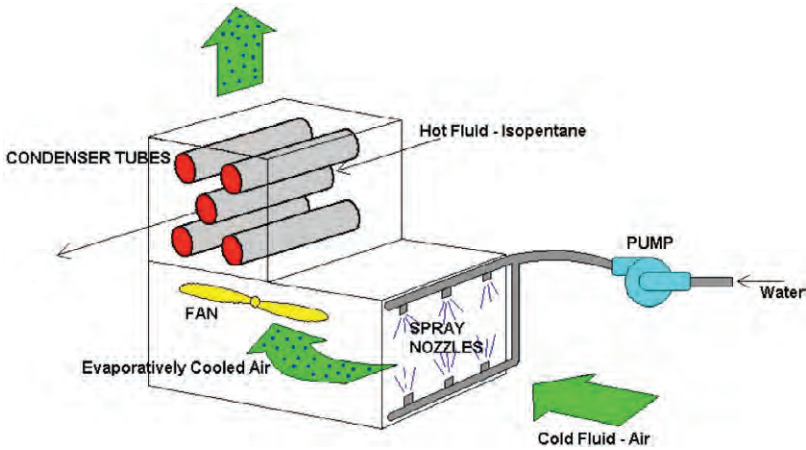


Figure 43. Spray nozzle evaporative cooling system

Figure 44, which plots the monthly performance for each system, shows that without an enhancement, monthly electric energy production drops from 850,000 kWh in the winter to 550,000 kWh in the summer. The three evaporative pre-cooling systems increase summer output to approximately 750,000 kWh. Deluge cooling is the only system that boosts summer output to winter levels or higher. This is not surprising because a deluged air-cooled condenser acts like an evaporative water-cooled condenser. Table 6 shows the economic results of the four evaporative cooling enhancement methods.

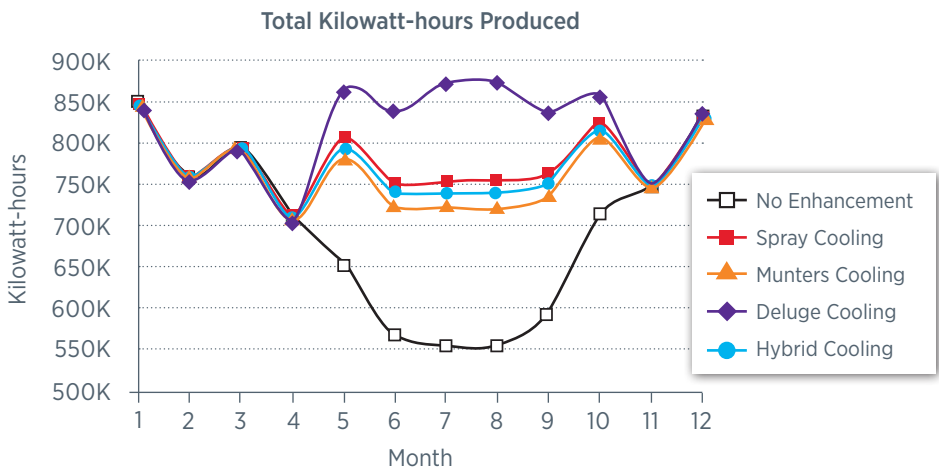


Figure 44. Monthly electricity production for evaporative cooling enhancement methods

Table 6. Economic results for the various evaporative enhancement methods

	SYSTEM 1: Spray Cooling	SYSTEM 2: Munters Cooling	SYSTEM 3: Deluge Cooling	SYSTEM 4: Hybrid Cooling
Total Capital Cost [\$]	\$155,977	\$184,530	\$37,139	\$134,911
Additional kWh produced per year with system [kWh]	1,013,085	855,851	1,496,471	947,359
Total Value of Additional Electricity [Present Value \$]	\$413,888	\$384,856	\$622,823	\$386,562
TLCC – Total Life-Cycle Cost [Present Value \$]	\$307,084	\$331,449	\$182,948	\$209,469
NPV – Net Present Value [Present Value \$]	\$106,804	\$17,407	\$439,875	\$177,093
LCOE –Levelized Cost of Additional Energy [Additional Cost per year / kWh gained per year]	\$0.0469	\$0.0599	\$0.0189	\$0.0342
SPB – Simple Payback Years	5	7	1	4
IRR – Internal Rate of Return	23.2%	16.0%	164.8%	32.1%

As shown, simple payback ranged from one year for the deluge system to seven years for the Munters packing. The deluge system not only performed well but had low estimated capital costs. The research clearly illustrated the potential benefit of using evaporative cooling enhancement in the summer. Practical considerations that must be considered, including the potential corrosion of finned tubes in a deluge system application, however, are difficult to factor into the cost-performance numbers.

5.4 Findings and Conclusions

DOE-supported researchers conducted a wide range of projects to reduce the impact of power plant operations on power generation costs, including the following work:

- Instruments based on near-infrared, tunable diode, laser spectroscopy were designed to continuously monitor hydrogen sulfide and hydrogen chloride, a high priority for industry due to abatement costs.
 - Laser frequency was matched with the absorption wavelengths of the targeted species making the technique readily adaptable to many gas species.
 - Investigations validated the feasibility of using laser spectroscopy to perform the desired measurements; during field testing, all of the engineered attributes of the system were shown to work as expected. The monitor continuously measured hydrogen sulfide with detection sensitivities of approximately one ppmv.
 - To provide the ppbv sensitivity required in some process streams, it was found necessary to use higher power lasers operating at longer wavelengths. In recent years quantum cascade laser technology has been developed that operates at wavelengths where the absorption bands of the species of interest are much stronger and there is more isolation from interfering species. As demand from the telecommunications and defense industry grows, the cost to produce these lasers will decrease, and the laser spectroscopy monitor developed will be able to provide the high sensitivity required.
- An in situ, optical steam quality monitor was developed that produced a direct, rather than inferred, indication of the presence of water. The technology was licensed to Thermochem for commercial development.
 - The steam monitor used very sensitive spectroscopic techniques that provided increased sensitivity, accuracy, and range relative to existing technologies.
 - The steam monitor was installed and operated at a commercial plant for 150 days. During this extended deployment, the device successfully tracked small changes in moisture content that occurred during scheduled operations (e.g., turbine water washes) and abnormal operation occurrences. The monitor operated with minimal impact to the plant operation and had no serious maintenance issues.
 - Testing suggested that the steam monitor's signal degradation over time could indicate potential scaling of turbine surfaces and serve as a timely indicator of both the necessity for and required duration of a turbine water wash.

- Investigations characterized the level and types of microbial activity in geothermal plant cooling systems. In addition to characterizing the microbial communities (i.e., types of microbes including sulfur-reducing, anaerobic, etc.), seasonal variations in biological activity were identified in a number of operating plants.
 - Various methods of monitoring the biological activity were evaluated. Of these, the electrochemical monitor, BloGEORGE™ Biofilm Activity Monitor, appeared to be the most cost effective. It is the only technique that allowed for the continuous monitoring of microbial activity, and as such, can be used to optimize the application of the biocide and minimize the adverse impact of the biofilm formation on power plant performance.
- An NCG removal system developed by INL for binary power plants was shown to be a technically viable means of minimizing the effect of NCGs on a binary plant. Field testing demonstrated the potential to increase plant output by as much as 4 percent with working fluid losses one-twentieth of those incurred using conventional removal practices. Mammoth Pacific Geothermal, LP uses the system, and the technology has been licensed to Membrane Technology Research.
 - Membrane separation technology improved separation of hydrocarbons from NCGs, allowing for the continuous venting of NCGs from a plant with minimal working fluid losses.
 - In over two years of field testing, the membranes continued to perform as predicted, with no operating or maintenance issues.
- Studies of the off-design operation of air-cooled binary plants identified ways to increase power production when ambient temperatures exceed design parameters or resource productivity declines. Evaporative pre-cooling of air was estimated to increase annual power sales from 3 to 18 percent, depending on the type of cooling system used, plant design, and resource temperature. Mammoth Pacific Geothermal, LP originated the concept as a way to offset the effect of higher ambient temperatures on power output. NREL and INL provided system and performance evaluation support. Mammoth uses cooled geothermal fluid as the source of water for this evaporative augmentation. Concerns regarding water quality have precluded the use of evaporative cooling at some locations. For these locations, the use of coated tubing and fins and perhaps deluge cooling, as suggested by NREL, could add power production benefits.

- o The use of VFDs on pump and fan motors in geothermal plants would provide operators with flexibility in managing the plant's house load when there is a decline in resource productivity. The projected additional power produced in one scenario was 4 percent. Plant operators are increasingly adapting VFDs, primarily for geothermal fluid production pumps and to a lesser extent, injection pumps.
- o Mammoth Pacific Geothermal, LP has adapted the concept of minimizing superheat in the vapor entering the turbine as a means of increasing performance with declining resource productivity. The benefits from this have varied from 1 to 10 percent in Mammoth's plants. The cost of incorporating this concept (i.e., instrumentation to monitor turbine inlet and exhaust conditions) is small—in this instance less than \$10,000.

A significant portion of power plant operations research was accomplished in partnership with industry, including Calpine Corporation; NCPA; Ormat Technologies, Inc.; Mammoth Pacific Geothermal, LP; Utah Municipal Power Agency; SB Geo Inc.; Thermochem; and MTR. Industry involvement significantly facilitated technology transfer and commercialization. Thermochem and MTR licensed the resulting technologies, and Mammoth Pacific Geothermal, LP uses the modified turbine inlet condition concept and membrane separation technology in its plants.

6.0

Power Plant Analytical Studies

DOE sponsored numerous power plant studies; several are listed in the Notes. These studies frequently showed the benefits of specific technologies or concepts, providing the basis or justification for further research. The efforts discussed here are not specific to a particular research area or need. They include earlier efforts that remain relevant today, as well as more recent work that was done to characterize the cost and performance of geothermal plants.

6.1 Geothermal Sourcebook

In the late 1970s, a small team at Brown University began to document the current knowledge on converting geothermal energy into electricity. As work progressed, the team grew to include members of government, academia, industry, and national laboratories—each contributing expertise to the final product. The resulting *Sourcebook on the Production of Electricity from Geothermal Energy*, (the Geothermal Sourcebook) a handbook on geothermal energy, was published in 1980.⁹ A companion publication, *Geothermal Energy as a Source of Electricity*, an overview of geothermal power projects worldwide, was published later that year.⁵

The Geothermal Sourcebook is a definitive reference, covering the diversity of components, cycles, and technologies needed to produce power from geothermal energy. Over 25 years later, much of the information provided in the Geothermal Sourcebook remains relevant and useful to industry and researchers.

6.2 Next Generation Geothermal Power Plants

In the mid-1990s, a consortium of government agencies, including DOE, and western utilities funded a study to assess different concepts for future geothermal power plants. EPRI managed the study, CE Holt Company was the contractor, and Fuji Electric Company and Barber-Nichols Engineering provided support. The study examined the use of flash-steam and binary power cycles for 10 resource scenarios that were representative of known geothermal sites in the western United States with temperatures of 129°C to 299°C (265°F to 570°F). In addition to detailing the 10 sites' specific resource conditions

and ambient conditions, the study applied a consistent set of assumptions to evaluate the performance and capital costs of a hypothetical 50-MW plant located at each site. These assumptions were based upon conversion technologies currently used by industry. Investigators also examined the effect of new power cycle concepts that might be used to lower power generation costs.

For binary cycles, the study found that the use of mixed working fluids consistently reduced the cost of power by approximately 7 percent when compared with commercial binary. A synchronous turbine concept had the potential to lower cost, but it required developmental work to verify performance and costs. Metastable expansions provided benefits with a declining resource and for plants whose performance was not impacted by an outlet temperature constraint on the geothermal fluid. With the flash cycles, the results showed minimal reduction in costs using a rotary separator turbine. Other advanced concepts examined for the flash cycle yielded little cost benefit.

Published in 1995, the final report, “Next Generation Geothermal Power Plants,”¹⁰ remains one of the most detailed and relevant cost studies on geothermal power plants. It is still referenced by researchers.

6.3 Geothermal Electricity Technology Evaluation Model

Researchers from Princeton Energy Resources International, LLC (PERI), INL, NREL, Sandia National Laboratories (SNL), and contractors developed a model that allowed DOE to evaluate the impact of its research on the cost of generating electrical power.¹¹⁴ The first Geothermal Electricity Technology Evaluation Model (GETEM) was completed and documented in 2006. GETEM predicts the cost of power based on a set of user-defined parameters (36 for a binary plant) in order to define plant performance and cost, well field size and costs, exploration and confirmation costs, and operating costs. Capital and operating costs are used to predict the cost of power for a reference or baseline condition.

GETEM continues the tradition DOE began in 1974—using computer-based models to better understand the cost and performance of the main components of geothermal power systems. GETEM clearly reflects significant technology improvements and cost reductions that have occurred over the past 35 years.¹¹⁵

GETEM allows the user to vary a number of parameters to reflect technological improvements that increase performance or lower capital or operating costs, and it predicts the impact of these improvements on the total cost of power. The model lets DOE assess where ongoing or proposed research has or would have the greatest impact on reducing power generation costs. Although development of the model emphasized air-cooled binary technology, GETEM includes both binary and flash-steam conversion systems.

INL contributed to GETEM by developing power plant cost and performance correlations that were used to establish plant cost and well field size. These correlations were based on limited published data including that from EPRI's "Next Generation Geothermal Power Plants" study. INL's correlations predicted plant cost as a function of resource temperature and plant size. Methods used to derive power plant costs were modified to include plant performance as a variable in the next version of GETEM.

In the newer version of GETEM, binary plant performance can be varied until the reduced well field costs associated with a more efficient plant (fewer wells are required) are offset by the increased plant costs associated with improved efficiency. In this way, plant performance can be optimized while minimizing total project capital costs (in \$/kW). Examples of GETEM's results are shown in the following figures.

In Figure 45(a), costs for a 10-MW plant are predicted for different well cost and geothermal fluid pumping scenarios. In Figure 45(b), the geothermal fluid flow is fixed. Results show that as well field cost increases, the minimum total project capital cost occurs at higher plant performance (brine effectiveness). While the model's predicted results are far from definitive, they more accurately represent how costs vary in actual plants, helping to explain variations in industry-supplied costs for power plants. Additionally, the model and its results help to better understand resource conditions for which energy conversion concepts that improve performance are viable. This model is being integrated into GETEM in an ongoing process to support geothermal systems analysis for planning purposes.

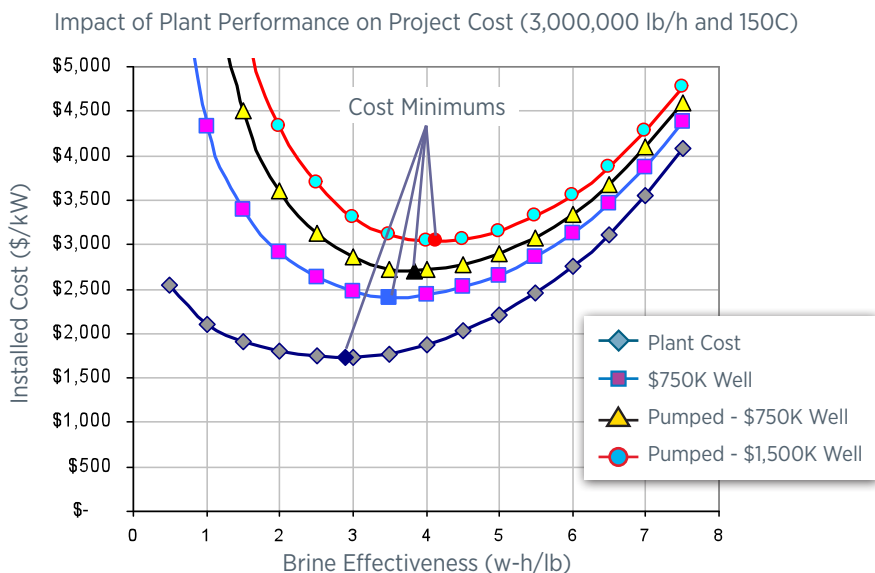


Figure 45(a). GETEM showing the impact of different well field cost scenarios on the total cost of an air-cooled binary project

Impact of Plant Performance on Project Cost (10MW Plant and 150C Resource)

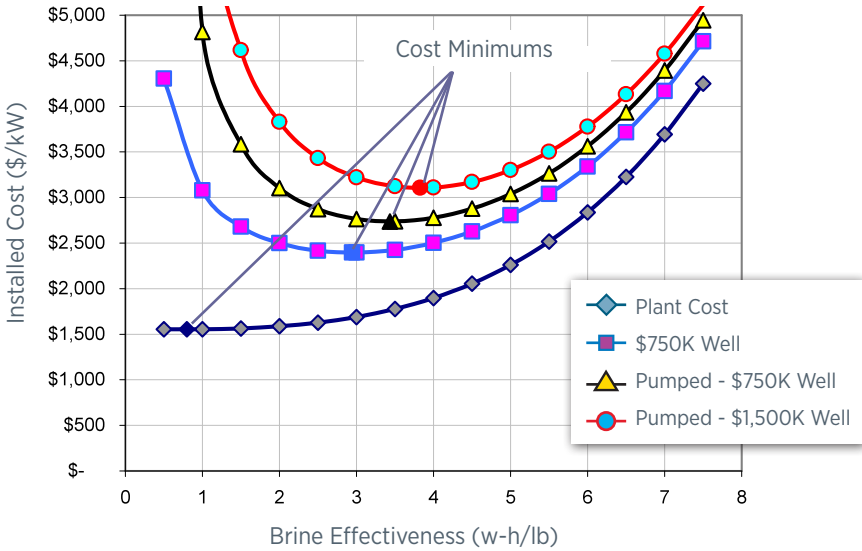


Figure 45(b). GETEM showing the impact of different well field cost scenarios on the total cost of an air-cooled binary project

6.4 Findings and Conclusions

Published in 1978 and 1994 respectively, the DOE-funded reports, the *Sourcebook on the Production of Electricity from Geothermal Energy* and EPRI's *Next Generation Geothermal Power Plants* provided industry and researchers pertinent information about geothermal energy conversion systems which remains relevant today.

GETEM was developed by several of the national laboratories to predict the cost of electricity and analyze research's impact on that cost. The first generation of GETEM is used by DOE management and researchers. Improvements to the model for purposes of guiding future research continue to this day.

Conclusion

At the beginning of DOE's geothermal R&D program, the U.S. geothermal industry was small and struggling to gain acceptance from utilities and financial institutions, which had only a rudimentary understanding of the costs and risks associated with geothermal energy projects. There was little solid data in the public domain on which reliable analyses of geothermal reservoirs as viable energy resources could be based. Reluctance to support geothermal projects financially was causing stagnation in the nascent geothermal industry. In addition, there was only limited understanding of the nature of geothermal systems and of how they could be gainfully used.

The DOE-funded research on energy conversion described in this report—along with the work described in companion reports on Drilling, Exploration, and Reservoir Engineering—had an immediate and profoundly positive effect by stimulating development of the modern geothermal industry. This achievement was realized through performance of collaborative projects in which DOE-funded scientists and engineers from the national laboratories, academic institutions, and the private sector worked with colleagues in companies, other government agencies, and institutions in other countries to address the full range of problems inhibiting economic geothermal development. Research priorities were continually assessed and updated in close collaboration with industry to ensure that project results would be of practical use. The success of DOE's program can be seen in today's vital and progressive geothermal industry.

Over three decades, from 1976 to 2006, the Department's supported a wide range of R&D to overcome challenges in energy conversion with the goal of making geothermal electricity more cost-competitive. Over three decades, DOE's support of energy conversion R&D focused on areas such as test facilities and demonstration plants; materials development; fluid chemistry; and power plant design, engineering, operations, and analytical studies. This work contributed to a decrease in the cost of geothermally generated electricity, and many of the government-supported technologies were adopted and commercialized by the U.S. geothermal industry.

The Department continues to support research and development activities and industry partnerships to encourage and help the U.S. geothermal community to meet these challenges, building on the technical research base of the past 30 years. This technical base provides the information and understanding necessary to create more efficient, reliable, and economic technologies, enabling the U.S. geothermal industry to compete for baseload electricity generation. It is hoped that this summary of prior work in energy conversion R&D will allow future geothermal developers and researchers to translate past efforts.

Appendix A:

Budget history of the federal geothermal research program, 1976 – 2006

Notes on Budget Table

The following discussion is provided to clarify the meaning and intent behind the estimates given in the Geothermal Program budget table (Fiscal Years 1976 – 2006). Despite the precision of the table, the reader is cautioned not to accept the amounts quoted in any single year as a fully accurate representation of the funds spent on a given technical area. The reasons for this caution will become apparent from the notes. However, over the entire period covered by this history, the totals are considered reasonably accurate.

1. The funding history covers FY 1976 through FY 2006 inclusive. FY 1976 includes funding for the “transition quarter” in which the Federal fiscal year was advanced three months from June 30 to September 30. All funds are in current year dollars in thousands; no adjustments were made to cover the time value of money.
2. The Program budgets were divided among the four major technical research topics comprising the focus of the history: Exploration, Drilling, Reservoir Engineering, and Energy Conversion. For convenience, subsets of Reservoir Engineering—Geopressured-Geothermal, Hot Dry Rock and Enhanced Geothermal Systems—are listed separately to identify funds spent on those topics versus Hydrothermal Reservoir Engineering. The technical areas covered by these research topics are summarized in the Table of Contents of each history.
3. Additional line items are included for completeness. They lie outside the four research areas as defined, but they appear in the Program budget for extended periods. Those line items are mentioned briefly here:
 - **Capital Equipment** – Tools and equipment needed to carry out research, typically at the national laboratories, are identified as capital equipment. Over time, this line was either reported independently within each program area (e.g., equipment for Geopressured Resources) or included as an aggregate total for the entire program. The aggregate total is used in this budget table. In some instances this may lead to discrepancies in budget amounts between what is listed here and amounts given by other sources. The differences are minor, since capital equipment was typically a small percentage of the total budget for any line item.
 - **Program Direction** – This line covers the personnel expenses of DOE staff used to plan, implement, and manage the Geothermal Program. After FY 1995, Program Direction was aggregated at the level of the Office of Energy Efficiency and Renewable Energy, eliminating this line from the Program budget.

- **Baca Demonstration Plant** – This major project was planned as the first commercial-scale (50 MWe) liquid-dominated hydrothermal power plant in the U.S. The project was located at the Valles Caldera, New Mexico, as a government-industry partnership. The industry partners were Unocal Geothermal and Public Service of New Mexico. The project was canceled in 1983 after attempts to find adequate hydrothermal resources to support the 50 MWe plant were unsuccessful.
 - **Environmental Control** – During the formative years of the Program, research was sponsored on a number of environmental topics that could have a detrimental impact on geothermal development. Topics studied to varying degrees included: hydrogen sulfide emissions, other non-condensable gas emissions, liquid effluents, land use, noise, induced seismicity, and subsidence. Environmental monitoring networks were established, notably at The Geysers, Imperial Valley, and the Gulf Coast, to collect data on subsidence and seismicity. Research was performed on environmental mitigation technology, especially hydrogen sulfide abatement.
 - **Geothermal Heat Pumps** – While use of heat pumps had been a minor secondary topic for much of the Program's history, the topic became a major program element for a five-year period (FY 1995 – FY1999) when a large education and outreach effort was conducted to acquaint the public with the environmental and efficiency benefits of this technology. Research on heat pump technology was limited but did include advancements in impervious grouts and improved performance models.
 - **GeoPowering the West** – This was an education, outreach, and technical support effort, launched in 2000 and patterned after the successful Wind Powering America initiative.
 - **Other** – A potpourri of activities not covered elsewhere are included here, such as policy, planning, and analysis done by the Program and short-lived projects such as non-electric (direct use) demonstrations. These activities are not covered in this history.
4. The source of the budget amounts reported here is the annual DOE budget request to Congress, often referred to as the President's Request or the Congressional Budget Request (CBR). In most cases, the amounts shown are "Actual" funds budgeted for a given line item as stated in the CBR. The "Actual" funds are not necessarily the amounts appropriated by Congress for that fiscal year---differences can arise due to reductions, rescissions, or other adjustments to the budget subsequent to initial appropriations.
 5. The CBR is submitted early in the calendar year, shortly after the President's State of the Union message, in order to give Congress the time needed to prepare appropriations bills before the start of the new fiscal year on October 1. Due to this scheduling of the CBR, "Actual" expenditures are reported with a two-year lag. For example, if we wished to know the actual amounts budgeted in FY 1989, they would be found in the FY 1991 CBR. FY 1989 would have ended on September 30, 1989, four months before the submission of the FY 1991 CBR to Congress. Sufficient time would have elapsed to allow a final accounting of FY 1989 expenditures, in most cases to the nearest dollar. This explains why

the funds are typically reported to 4-5 significant figures, rounded to thousands. Note that in this example the FY 1990 CBR would not be a source of complete information about FY 1989 expenditures because the FY 1990 CBR would have been submitted in early 1989, before the end of FY 1989. Therefore, the “Actual” funds reported in the CBR are considered the best source of expenditures for the fiscal year in question.

6. A major problem in using “Actual” CBR amounts stems from the fact that neither the Program nor the CBR were constant over the course of time. The Program’s organization changed on a number of occasions during its 30-year history, and the format and content of the CBR changed as well. Probably the greatest impact on recreating the budgets for the topical research areas was the fact that in many cases the amounts spent on exploration, drilling, reservoir engineering, and energy conversion were aggregated under some generic title. For example, during the 1980s the major categories of Geothermal Program funding were: Hydrothermal Industrialization, Geopressured Resources, and Geothermal Technology Development. Hydrothermal Industrialization included sub-topics such as field demonstrations, test facilities, state resource assessments, and industry-coupled drilling. Technology Development covered many diverse research sub-topics such as hot dry rock, advanced drilling, geochemical engineering and materials, energy conversion, and geoscience. In some cases, the expenditures for these topical areas (e.g., hot dry rock) were reported, and the budgeted amounts could be properly allocated. However, the CBR did not always report “Actual” expenditures to that level of detail, and the amounts had to be inferred from the “Request” amount given in the CBR for the fiscal year in question. These amounts could become problematic when CBR formats changed or major programmatic reorganizations were instituted between the year of the “Request” and the “Actual” reporting year.
7. Another complicating factor was the merging of technical areas under a generic topical area. For example, the line item, “Geoscience Technology,” subsumed the research topics of exploration and reservoir engineering. The amount of budget devoted to each element was usually not specified in the CBR. The problem is particularly vexing for budgets dating from FY 1999 when budget line items such as “University Research”, “Core Research”, “Technology Deployment”, and “Systems Development” came into use. Fortunately, Program budget records apart from the CBR for this period are fairly complete, allowing assignment of funding to the appropriate research areas.
8. Despite the aforementioned caveats, many of the budget estimates are judged to be accurate. Geopressured-Geothermal was a unique line item in the budget that could be easily tracked from year to year in the CBR. Funding for Hot Dry Rock was reported separately for the life of that program. The same can be said for Capital Equipment, Program Direction, Baca Plant, and Geothermal Heat Pumps. Of the four research topical areas, Drilling Technology had the best record of budget representation over time, followed by Energy Conversion. Due to their technological similarities, Exploration and Reservoir Engineering could be difficult to distinguish. As stated above, the funding for the topical areas in any given year may reflect some uncertainty, but the aggregate totals over 30 years do provide a good estimate of relative funding levels.

**Geothermal
Program
Annual Budget
(\$000)**

	Exploration	Drilling	Reservoir Engineering	Hot Dry Rock	EGS	Geopressed-Geothermal	Energy Conversion
1976	\$6,280	\$4,206		\$5,274		\$1,182	\$21,209
1977	\$9,000	\$3,500		\$5,280		\$6,620	\$22,350
1978	\$17,600	\$2,870		\$5,400		\$17,100	\$40,630
1979	\$31,270	\$9,000	\$8,500	\$15,000		\$26,600	\$33,169
1980	\$15,506	\$8,800	\$5,100	\$14,000		\$35,700	\$30,294
1981	\$25,224	\$12,545	\$6,547	\$13,500		\$35,600	\$24,920
1982	\$3,450	\$3,036	\$2,650	\$9,700		\$16,686	\$28,858
1983	\$2,360	\$1,710	\$400	\$7,500		\$8,400	\$29,641
1984	\$2,713	\$2,640	\$10,172	\$7,540		\$5,000	\$1,105
1985	\$3,215	\$3,585	\$5,623	\$7,444		\$5,226	\$2,280
1986	\$4,094	\$2,415	\$5,497	\$7,631		\$4,426	\$1,250
1987	\$0	\$1,350	\$5,595	\$8,000		\$3,940	\$1,065
1988	\$455	\$1,775	\$5,355	\$5,770		\$4,955	\$1,580
1989	\$0	\$2,250	\$4,085	\$3,500		\$5,930	\$1,935
1990	\$0	\$2,140	\$3,761	\$3,290		\$5,523	\$1,601
1991	\$6,925	\$2,435	\$5,543	\$3,627		\$5,884	\$2,155
1992	\$1,300	\$2,700	\$7,100	\$3,600		\$4,916	\$5,300
1993	\$2,080	\$5,635	\$5,517	\$3,600			\$4,520
1994	\$2,597	\$3,400	\$6,466	\$1,300			\$6,403
1995	\$5,977	\$6,267	\$4,620	\$4,000			\$5,090
1996	\$8,700	\$5,899	\$0	\$1,900			\$5,200
1997	\$9,818	\$5,030	\$0	\$400			\$5,900
1998	\$5,600	\$6,900	\$4,387				\$5,119
1999	\$4,084	\$4,934	\$6,782				\$4,150
2000	\$1,475	\$5,500	\$7,025		\$3,049		\$3,405
2001	\$2,700	\$5,500	\$5,600		\$1,700		\$4,745
2002	\$3,000	\$5,084	\$5,336		\$1,580		\$4,111
2003	\$4,163	\$5,717			\$5,915		\$8,111
2004	\$3,000	\$6,000			\$6,680		\$5,226
2005	\$3,534	\$4,060			\$6,788		\$5,180
2006	\$3,734	\$4,128			\$5,928		\$3,592
Total	\$189,854	\$141,011	\$121,661	\$137,256	\$31,640	\$193,688	\$320,094

	Capital Equipment	Program Direction	Baca	Environmental Control	Geothermal Heat Pumps	Geopowering the West	Other	TOTAL
\$704			\$1,301			\$2,958		\$43,114
\$1,500			\$2,500			\$2,300		\$53,050
\$2,500		\$12,000	\$3,600			\$4,500		\$106,200
\$3,000	\$663	\$7,450	\$516			\$10,500		\$145,668
\$3,200	\$1,100	\$20,500	\$1,300			\$12,200		\$147,700
\$1,310	\$2,376	\$12,050	\$2,600			\$19,959		\$156,631
\$860	\$1,600	\$2,124	\$500					\$69,464
\$250	\$1,250					\$5,963		\$57,474
\$0	\$1,000					\$100		\$30,270
\$400	\$1,025					\$900		\$29,698
\$481	\$701							\$26,495
\$0	\$780							\$20,730
\$0	\$835							\$20,725
\$795	\$826							\$19,321
\$426	\$782							\$17,523
\$401	\$889					\$2,479		\$30,338
\$821	\$1,000			\$200				\$26,937
\$900	\$1,000							\$23,252
\$873	\$970		\$1,000					\$23,009
\$886	\$1,000		\$967	\$5,000		\$4,000		\$37,807
				\$5,300		\$2,400		\$29,399
				\$6,482		\$2,000		\$29,630
				\$6,400		\$288		\$28,694
				\$6,420		\$1,780		\$28,150
						\$2,882		\$23,336
					\$1,600	\$4,778		\$26,623
					\$3,200	\$4,724		\$27,035
					\$3,521	\$963		\$28,390
					\$2,738	\$981		\$24,625
					\$3,128	\$2,666		\$25,356
					\$2,658	\$2,722		\$22,762
\$19,307	\$17,797	\$54,124	\$14,284	\$29,802	\$16,845	\$92,043		\$1,379,406

Abbreviations & Acronyms

ADCC	advanced direct-contact condenser	Fe	iron
Ag	silver	FISH	fluorescently tagged, in situ hybridization
APST	aminopropylsilane triol	fpi	fins per inch
As	arsenic	GEA	Geothermal Energy Association
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers	GETEM	Geothermal Electricity Technology Evaluation Model
ATP	adenosine triphosphate	GLEF	Geothermal Loop Experimental Facility
Au	gold	GPTF	Geothermal Pump Test Facility
BNL	Brookhaven National Laboratory	GRC	Geothermal Resources Council
CaCl₂	calcium chloride	GTF	Geothermal Test Facility
CAST	Cycle Analysis Simulation Tool	H₂S	hydrogen sulfide
Ce	cerium	HCl	hydrogen chloride
CEC	California Energy Commission	HCRF	Heat Cycle Research Facility
Co	cobalt	HF	hydrogen fluoride
CO₂	carbon dioxide	Hg	mercury
Cr	chromium	HNO₃	nitric acid
CRC	Crystallizer Reactor Clarifier	hp	horsepower
DC	direct current	HTRI	Heat Transfer Research, Inc.
DCHX	direct contact heat exchanger	IGT	Institute of Gas Technology
DGGE	denaturing gradient gel electrophoresis	INEEL	Idaho National Engineering and Environmental Laboratory
DNA	deoxyribonucleic acid	INL	Idaho National Laboratory
DOE	Department of Energy	kWh	kilowatt-hour
EDTA	iron chelate Dow RT2	lb/h	pounds per hour
EGS	enhanced geothermal system	LBNL	Lawrence Berkeley National Laboratory
EPRI	Electric Power Research Institute	LCOE	levelized cost of electricity
ERDA	Energy Research and Development Administration		

LEC	Levelized Energy Cost	PEC	performance evaluative criteria
Li	lithium	PEEK	polyetheretherketon
LIBD	laser-induced breakdown detection	PERI	Princeton Energy Resources International, LLC
LLNL	Lawrence Livermore National Laboratory	PES	polyarylethersulfone
mg/L	milligrams per liter	PLFA	phospholipid fatty acid
MIT	Massachusetts Institute of Technology	PNNL	Pacific Northwest National Laboratory
mm	millimeter	ppbv	parts per billion by volume
MMT	montmorillonite	ppm	parts per million
Mn	maganese	ppmv	parts per million by volume
MPN	most probable number	PPS	polyphenylene sulfide
MTR	Membrane Technology and Research, Inc.	psia	per square inch absolute
MW	megawatt	psig	per square inch guage
Na₂SO₄H₂O	sodium sulphate	R&D	research and development
NaCl	sodium chloride	RO	reverse osmosis
NaOH	sodium hydroxide	SBTF	Single-Blow Test Facility
NCG	noncondensable gas	scf	standard cubic foot/feet
NCPA	Northern California Power Agency	SDG&E	San Diego Gas and Electric
NDT	Non-Destructive Testing	SiO₂	quartz
NREL	National Renewable Energy Laboratory	SNL	Sandia National Laboratories
O&M	operation and maintenance	TDS	total dissolved solids
OMP	organometallic polymers	TOC	total organic carbon
ORNL	Oak Ridge National Laboratory	U	uranium
PAAMPA	poly-acetamide-acetoxyl methyl-propylsiloxane	USGS	U.S. Geological Survey
Pb	lead	VFD	variable frequency drives
PbS	phosphate buffered saline	W/m	watts per meter
		w-hr/lb	watt-hours per pound
		Zn	zinc

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