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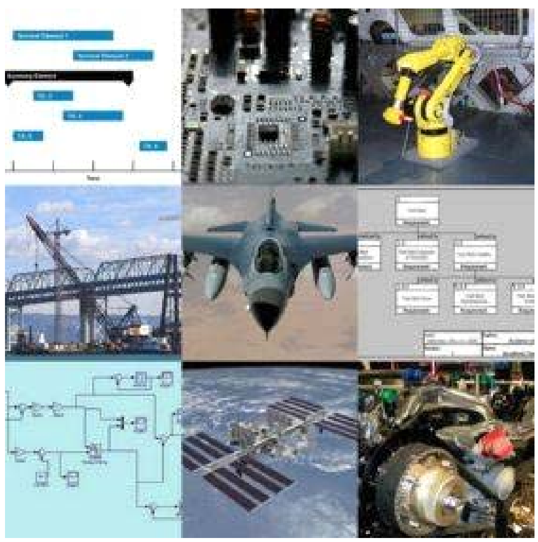

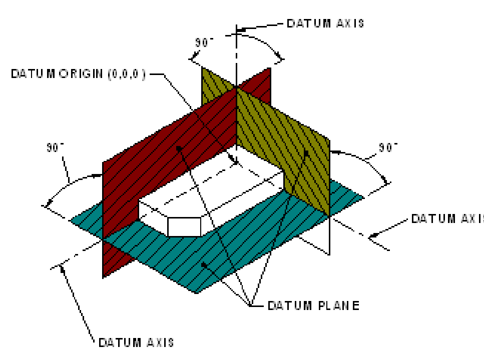

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U.S. Department of Energy

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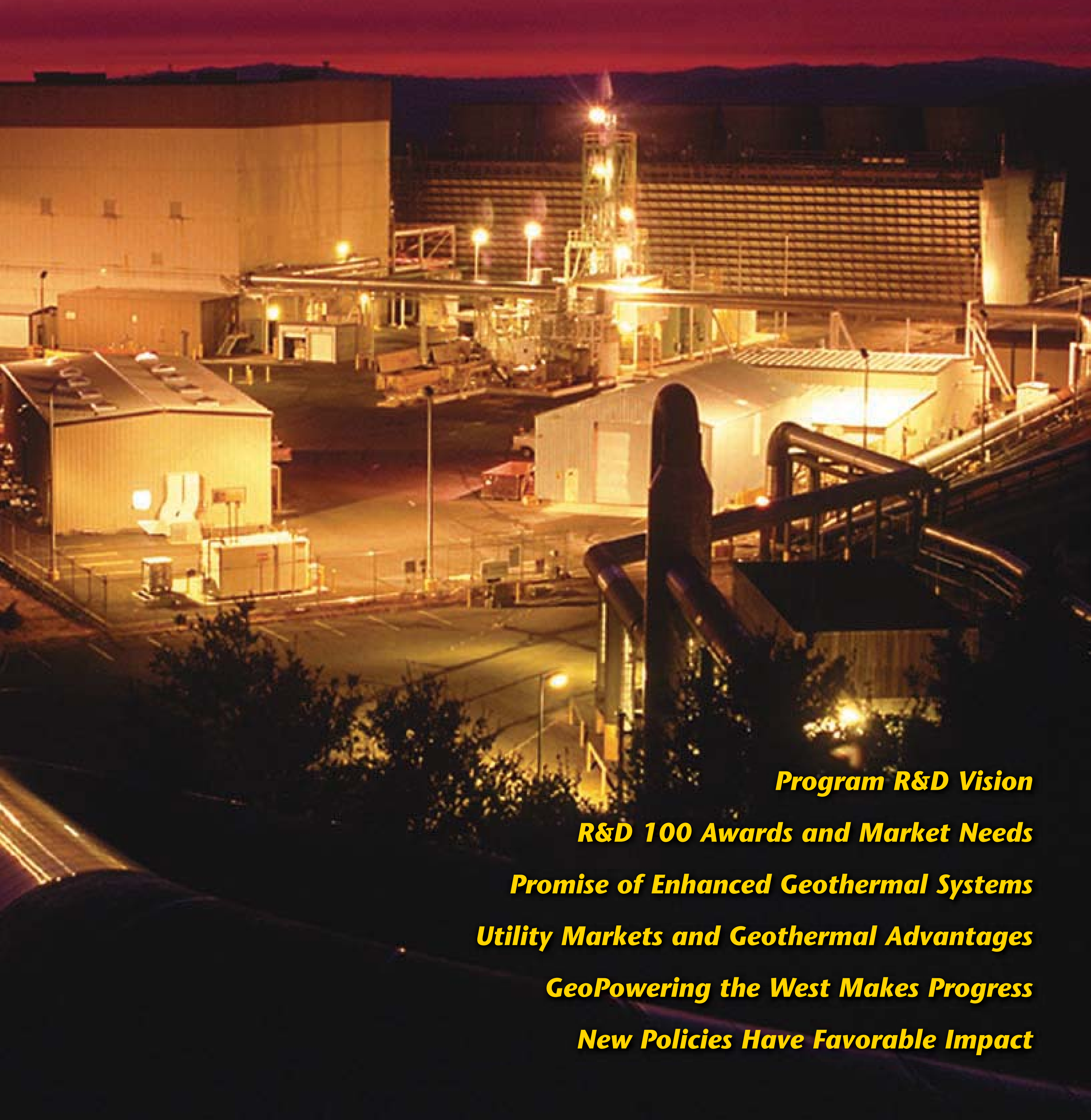
Geothermal Today

U.S. Department of Energy

2005 Geothermal Technologies Program Highlights



Program R&D Vision

R&D 100 Awards and Market Needs

Promise of Enhanced Geothermal Systems

Utility Markets and Geothermal Advantages

GeoPowering the West Makes Progress

New Policies Have Favorable Impact

Cover photo - Sonoma geothermal power plant at The Geysers. Credit - PG&E, now Calpine.

About "Geothermal Today"

The geothermal energy potential beneath our feet is vast. This tremendous resource amounts to 50,000 times the energy of all oil and gas resources in the world. And geothermal energy is clean; it represents a promising solution for the nation and the world as they become ever more concerned about global warming, pollution, and rising fossil energy prices. Furthermore, increased development of geothermal energy gives people the potential to gain better control of their own local energy resources and use a secure, safe, domestic source of energy.

Today's U.S. geothermal industry is a $1.5-billion-per-year enterprise involving over 2800 megawatts (MW) of electricity generation, about 2000 MW of thermal energy in direct-use applications such as indoor heating, greenhouses, food drying, and aquaculture, and over 3,700 MW of thermal energy from geothermal heat pumps. The potential for growth is substantial.

The international market for geothermal power development could exceed $25 billion (total) for the next 10 to 15 years. At the present time, U.S. technology and industry stand at the forefront of this international market.

However, the cost of geothermal heat and electricity remains higher than the least-cost conventional technologies and the near-term market for geothermal energy is uncertain, presenting a major challenge for the U.S. geothermal industry. Significant work is still needed to lower costs and create incentives to spur the market for geothermal heat and power. The U.S. Department of Energy (DOE) Geothermal Technologies Program (the Program) is committed to supporting the geothermal industry with research and development to reduce costs and help geothermal energy fulfill its potential. This issue covers highlights from 2003.

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DOE Geothermal Technologies Program R&D Vision

The Promise of Geothermal Energy

The Earth houses a vast energy supply in the form of geothermal resources. Domestic resources are equivalent to a 30,000-year energy supply for the United States. However, only about 2,800 megawatts of geothermal power is installed today. Geothermal has not reached its full potential as a clean, secure energy alternative because of concerns or issues with resources, technology, industry commitment, and public policies. These concerns affect the economic competitiveness of geothermal energy.

The U.S. Department of Energy (DOE) Geothermal Technologies Program (the Program) has a vision of geothermal energy as the nation's environmentally preferred baseload energy alternative. Geothermal power plants have a proven track record of performance as baseload facilities, with capacity factors and availabilities frequently exceeding 90 percent. Modern energy conversion technology enables geothermal facilities to operate with only extremely low emissions. These factors, combined with the considerable size of the resource, argue for a significant share of geothermal energy in the future U.S. energy economy.

Strategic Directions

Only a small fraction of the nation's identified geothermal resource is economic today, with the shallow, high-temperature resources typically first to be developed. Exploration and resource verification can be uncertain and expensive. Power plant development and capital costs are often greater than conventional alternatives. Exploration and drilling costs must be lowered to bring more resources into production. Discovering, accessing, and developing the deep geothermal resources with lower permeability and fluid content will require significant improvements in both the technology and economics of geothermal development. The Program's goals also require addressing institutional issues that affect costs and inhibit development, such as federal leasing practices, regulations, and public awareness.

PIX 08876, Courtesy of Brookhaven National Laboratory

Dr. Eugene Premuzic, a geothermal researcher (retired) at Brookhaven National Laboratory. His research led to an R&D 100 Award (see page 7).

PIX 06152, NREL, David Parsons

Dr. Desikan Bharathan, NREL, performing research and analysis on energy conversion improvements for geothermal power plants. His research led to an R&D 100 Award (see page 4).


PIX 09054, University of Utah

Researchers conducting tracer test on Southwest Geysers Wastewater Recycling System.

Consequently, the Program has shifted its emphasis to longer-term, high-payoff research with cost-shared field applications, as opposed to nearer-term incremental improvements in technology with laboratory-based studies. *The Program's mission is to work in partnership with U.S. industry to establish geothermal energy as an economically competitive contributor to the U.S. energy supply.* The Program's goal in support of this mission is *to reduce market entry cost of electric power generated from Enhanced Geothermal Systems (EGS) to an economically competitive level*. To achieve this, the Program will focus on EGS and related technologies, demonstrating the technical viability of EGS technology by 2011.

Research and Development Vision

Working in partnership with U.S. industry, the Program's research and development (R&D) activities are organized to support both technology development and application. These activities include EGS; exploration and resource characterization; drilling and reservoir management; and power systems and energy conversion.

The Program's R&D vision is to foster the continued development of hydrothermal resources (near-term) and expand the potential for development of enhanced or engineered geothermal resources (long-term). Achieving this vision will help enable geothermal energy resources to make significant contributions to clean, reliable power production and economically feasible energy use in the western United States.

DOE's Award-Winning Geothermal Technologies Find Commercial Success

In the presence of CO_2, and hence carbonic acid, ThermaLock (left) remains unaffected for a long time, while Portland cement (right) quickly degrades.

During just five years, DOE's national laboratories have received six R&D 100 Awards for technologies supported by DOE's Geothermal Technologies Program. *R&D Magazine* annually bestows R&D 100 Awards—also known as the "Oscars of Invention"—for the 100 most technologically significant new products of the previous year. Therefore, these award-winning technologies not only represent DOE's presence at the forefront of geothermal technology research and development, but also an opportunity for successful commercialization.

Here are the stories behind these award-winning technologies—from the problems they addressed at the beginning to their bright, commercial futures.

Working Both Sides of the Turbine

Steam power plants, including geothermal power plants, work by having steam under high pressure drive a turbine blade. The force on the turbine blade is a function of both the pressure of the steam on the upstream side of the blade and the lack of pressure on the downstream side. The downstream vacuum is created by condensation of the spent steam. The problem is this: you don't want to let the steam that has already passed through the turbine build up on the backside of the turbine. If it does, the result is a pressure increase on the backside (known as back pressure), which ruins the vacuum on that side and makes it harder to pull the steam through the turbine to produce electricity. The spent steam must be efficiently condensed to enhance power production.

For flash or dry steam geothermal plants, there is another key challenge—the steam also contains hydrogen sulfide and other noncondensable gases. If these gases build up, they create backpressure and reduce power production. If they dissolve in the condensation water, the hydrogen sulfide in particular is expensive to treat. That is the challenge that Pacific Gas & Electric managers at The Geysers—the world's largest geothermal complex and one of only two blessed with dry steam—faced in 1992 and brought to Desikan Bharathan of the National Renewable Energy Laboratory (NREL).

And Bharathan was the right man for the job. A fluid-flow and heat-transfer expert, he had already designed a similar system for a different power technology (ocean thermal energy conversion… but that's a different story). The system was called "advanced direct-contact condensation" or ADCC. "Direct-contact" because cooling water mixes directly with the spent steam as opposed to being piped through heat exchangers. "Advanced" because the

NREL National Renewable Energy Laboratory

PIX 06241, Ron Judkoff

NREL's Desikhan Bharathan (right) receives his R&D 100 Award in 1999. This technology innovation improved plant performance.

geometry of the packings—plastic or metal plates to provide surface area for the steam and cooling water to mix on—are designed for maximum surface area and effectiveness.

At The Geysers, the greatest problem was occurring at Plant 11. Although Plant 11 was built to generate 110 million watts (MW), steam-field pressure losses had reduced its capacity to approximately 65 MW by the mid-1990s. Gas buildup in the condenser aggravated that power loss. In designing ADCC for Plant 11, Bharathan and colleagues at NREL used computer modeling to predict not only the most effective packing design for the plant, but also the chemicals (and their amounts) that would be in the water and those that would stay in the vapor. This important step enabled them to design an effective two-passage system that separates the noncondensable gases from the water vapor, minimizing the amount of hydrogen sulfide dissolving in the condensed water to make abatement easier.

When the refurbished condenser was installed during a planned shutdown in 1997, it was an unqualified success. It increased energy production by 5 percent and plant capacity by 17 percent, from 65 MW to 78 MW. For a business that counts fractions of percentage points as great successes, this was extremely good news. The system effectively reduced steam carryover to the gas removal system, thereby reducing costly backpressure. It also reduced absorption of hydrogen sulfide into the cooling water condensate. As a result, the amount of iron chelate used to treat the hydrogen sulfide could be cut in half — saving the plant a considerable amount of money.

PG&E sold The Geysers to Calpine, and NREL licensed ADCC for geothermal power use to Alstom, an international power generation service company. In the intervening years, Alstom went on to design ADCC retrofits for Calpine for Units 5 and 6 at The Geysers. Alstom just recently sold its North American condenser business to Connell Limited Partnership, which will merge it with their Yuba Heat Transfer business. Yuba is looking forward to aggressively promoting ADCC to the geothermal industry.

ADCC installation is even more cost effective for new facilities than for retrofits, and takes up only about half as much space as conventional condensers. Alstom had also already built condensers for two projects in Mexico, a pair of 5-MW geothermal plants at Tres Virgenes in Baja California, and four 35-MW units at Los Azufres, near Mexico City. With new geothermal plants planned in the Philippines and Indonesia, there is potential for ADCC to make a major contribution to geothermal power development, and it clearly warranted its 1999 R&D 100 Award.

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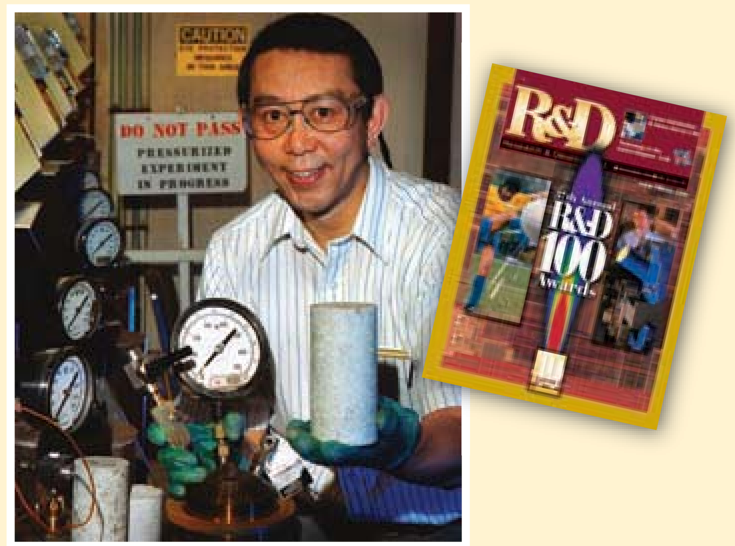

Toshi Sugama, Brookhaven National Laboratory, is shown with a sample of ThermaLock well cement.

Cementing a Growing Market

Before the turn of this century, drilling and cementing geothermal wells presented operators of geothermal facilities with a major problem. Using Portland cement—the industry standard for cementing oil and gas wells—just didn't work well for geothermal wells. The cement would not last more than a few months, and wells would have to be re-drilled and re-cemented.

This was the situation until Toshifumi Sugama of Brookhaven National Laboratory (BNL) got together with collaborators from Halliburton and Unocal to develop a new kind of cement. The cement they developed—which Halliburton has commercialized under the name of ThermaLock—not only won a 2000 R&D 100 award, it is becoming the preferred well cement for the geothermal industry, saving tens of thousands of dollars per well, and creating a growing market that today is worth many millions of dollars per year.

But why use cement in the first place? Drilling an oil, gas, or geothermal well requires drilling through different levels of rock and layers of sediment, which exist at different temperatures, have variable constituents (water, gas, brine, etc), and have different pressures and physical attributes. To isolate the wellbore from the rock and sediment, and the layers from one another requires steel casings—larger diameter pipe nearer the surface and piping of increasingly smaller diameter the greater the depth. To isolate and insulate the casings from the rock and sediment, and to keep the casings in place, cement is pumped through a feed pipe into the borehole surrounding the pipe, where it hardens to surround the casing.

There are several drawbacks to using Portland cement in wells that have the harsh environments common to geothermal wells, such as high acidity and high temperature. The first drawback is that Portland cement is based on calcium hydroxide ($Ca\,(OH)_2$) and calcium silicon hydrates (C-S-H), ingredients that chemically react with an acidic environment, disintegrating the cement and destroying its cement-like properties. Portland cement has low tensile strength and resiliency (i.e., is brittle, and so, it's less likely to deform without failure). Thus, under high stress, such as the thermal stress of high temperatures, it can crack and buckle.

But geothermal wells do not constitute the only hostile environment for Portland cement. Consider, for example, enhanced recovery techniques used at oil wells. For particularly viscous oils, steam is injected into an injection well to decrease the viscosity of the oil and increase the pressure on the reservoir. The temperature, however, often goes above 600°F (315°C), putting Portland cement under thermal stress and accelerating its deterioration. In other cases, carbon dioxide may be used in injection wells. This increases the pressure on an oil reservoir to force the oil to a recovery well to be pumped out. The carbon dioxide, however, will react with any water that is present to produce carbonic acid, which chemically reacts with the Portland cement and turns it into $Ca\,(HCO_3)_2$, which is no longer cement.

ThermaLock, on the other hand, is based on calcium phosphate hydrates, aluminate hydrates, and mica-like calcium aluminosillicates. With the appropriate slurry, this combination of materials forms a relatively hard cement with ceramic-like properties that withstands heat and that does not readily react with an acidic environment to lose its cement properties. The result is at least a 20-fold improvement for these harsh environments, with well casings being able to last up to 20 years.

ThermaLock has become a commercial success worth millions of dollars annually. Nonetheless, Halliburton considers it to be a success in a niche market. Niche because, compared with the main lines of Halliburton's well-cementing operations, geothermal use does not constitute a large market. Niche also with respect to enhanced oil recovery, because most of this recovery can safely use Portland cement. Still, this is a niche market with a growth potential that will correlate with the growth in demand for geothermal energy, and the need for enhanced oil recovery.

Thus far, ThermaLock has been used for:

- Geothermal projects in California, Indonesia, and Japan
- Enhanced oil recovery using carbon dioxide injection wells in Oklahoma
- Enhanced oil recovery using steam injection wells in Kuwait and New Zealand
- Casing repair and liner completions for a carbon dioxide flood field in Kansas
- Enhanced oil recovery using sour-gas injection wells in Wyoming (sour gas is a mixture of hydrogen sulfide and carbon dioxide, and is so-called because it is a by-product of "sour" hydrocarbon pools, which contain hydrogen sulfide and carbon dioxide
- Enhanced oil recovery using steam injection wells in California
- Off-shore oil recovery in the North Sea.

The last two of these projects used Halliburton's new foamed version of ThermaLock. To improve the original award-winning cement, Halliburton has added certain surfactants, along with the use of nitrogen gas, to produce the foamed version. This foamed version sets up the cement in a honeycomb configuration, giving it more air, making it lighter, increasing its insulating value, and making it more ductile. Thus, it is:

- Better able to withstand stress (largely because of greater ductility)
- Better applied to geothermal resources, because of greater insulating value, giving it the ability to retain geothermal fluids at higher temperatures for longer periods of time
- Less expensive, because it uses less raw material to fill the same space.

With this version of the technology, the cement and water are thoroughly mixed and forced through the feed pipe where, under a pressure of about

1,000 pounds per square inch, the mixture generates a foam with a structure akin to soap bubbles. Nitrogen gas is then forced down the pipe through a T-joint. When the nitrogen mixes with the foam, the foam flashes to a gas. The gas then sets up, creating the honeycomb cement structure.

For his part, Sugama is also improving the product in several ways, making it lighter, tougher, more ductile, and more resistant to stress and acid. In fact, he is working on improvements to make it resistant to acids down to a pH between 1.1 and 1.2. His goal is to make a cement that will enable casings of pipes to last 30 years or longer—a 100-fold improvement over Portland cement.

With these improvements from both Halliburton and BNL, we may not only see more facile geothermal applications and a growing market, we may also witness this superb concept winning another R&D 100 Award.

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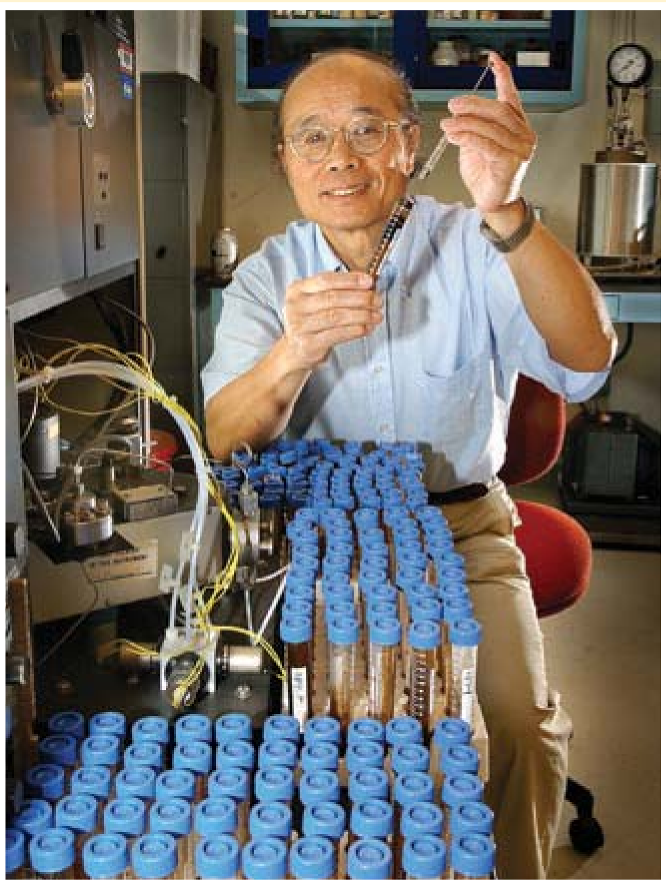

Brookhaven chemist Mow Lin, one of the inventors of the silica recovery process.

Where There's Muck, There's Money

Geothermal power potential is generally embodied in brines—hot saline water that can be brought to the surface and flashed to steam to drive a turbine. Without brine to bring the heat to the surface, the task of tapping geothermal energy is more challenging (see article on enhanced geothermal systems on page 12). But what do you do with the spent brine? Whether treating the brine for surface release or reinjecting it to help maintain the resource, as geothermal plants are increasingly doing, the brine carries with it an extra burden—dissolved minerals, particularly silica. As the brine cools, the silica precipitates out, scaling on and fouling the reinjection pumps, piping, and other equipment. Cleanup is costly and generates troublesome, frequently toxic, waste requiring disposal.

The Program turned to BNL scientist Eugene Premuzic, an expert in applying natural processes to technical challenges, for seeking a cost-effective and environmentally acceptable way to treat the precipitate waste and reduce its impact on geothermal equipment. Premuzic and BNL colleague Mow Lin, however, saw the challenge of this silica "mucking up" the equipment as an opportunity. In reviewing the options for treatment, they saw potential for producing commercial-grade silica, as well as valuable trace metals. High-purity silica is a commodity fine-chemical that is used for a wide range of products, some of which sell for as much as $100/gram.

Premuzic and his collaborator Lin started by looking at highly saline (300,000 parts per million or higher) geothermal brines, with their high-potential silica yields. The high salinity, however, also meant high content of other minerals, some toxic, as well as taking away from the purity of the desired silica. Premuzic and Lin developed systems to have groups of specialized microorganisms act on the minerals, converting them to water-soluble substances that could be easily removed. First, one consortium metabolized the arsenic and other toxics; then another the radioactive trace elements.

With DOE Program support, this system was tested on a side stream of spent brine at a Salton Sea geothermal plant in California. The system worked fine, but prompted the BNL team to expand their work, and they determined that lower-salinity brines (400 parts per million or less) might be more lucrative. Silica yields would be lower, but the purity would be higher, commanding a substantially higher price. Also, because silica's relative proportion of the mineral content was higher and the initial toxic contaminant levels were lower, the biochemical microbial treatment steps could be skipped and the patented process could start immediately with chemical treatment of the silica.

At the recommendation of the Program, the scientists teamed up with geothermal industry economics expert Stuart Johnson to help in moving from the lab to the power plant and designed a process specific for lower salinity brines. The new low-salinity process includes a patented step for chemically inducing precipitation of the silica. This process starts with spent brine instead of sludge. And because silica is the main scaling problem for such brines, the remainder can be passed along for reinjection without concern for fouling.

The system was tested at the Dixie Valley Geothermal Plant in Nevada, and produced very impressive results—99.9 percent purity silica with higher surface area and porosity than the leading commercial product and a 60 percent yield from the available silica. The return from silica sale was calculated as being sufficient to reduce the cost of electrical production from the plant by $0.011 cents per kilowatt-hour—a nearly 20 percent reduction!

Such a return is sufficient to very significantly improve the economics of geothermal power plant operations. Also, the process was subsequently tested at two other Nevada plants, and turns out to be effective on mid-salinity-level brines, as well, so could be applied to a large proportion of geothermal power plants. Not gold from lead, but truly money from muck, silica recovery could prove a huge boon to geothermal power development and more than worthy of its 2001 R&D 100 award. The Geothermal Resources Council also awarded Premuzic a 2001 'Special Achievement' award for the work.

(Editor's note: Lin tragically died after receiving the R&D 100 Award; Premuzic has since retired from BNL, but still consults and is pursuing implementation of the silica recovery technology in the private sector; Johnson, with Caithness Energy at the time of development of the silica recovery technology, is now with ORMAT, another leading geothermal power developer.)

Survival in a Tough Neighborhood

Corrosive, scaling, and hot—geothermal brines present quite a materials challenge. Spas and geothermal power plants with relatively mild brines may get by with standard carbon-steel pipes and other parts, or simply resign themselves to frequent replacement. Power plants with stronger brines, however, call for some sort of protection to avoid continual component replacement. Cement-lined pipes are a relatively standard practice, but the cement cracks or corrodes itself, exposing the steel,

NREL National Renewable Energy Laboratory

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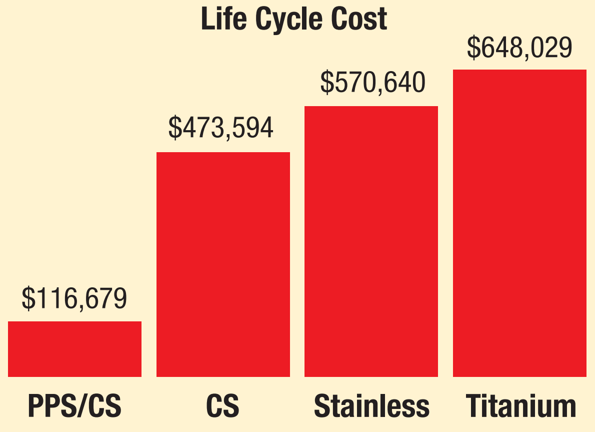
PPS coating on the left and a failed coating on the right.

limiting the duration of their usefulness. Other plants have gone to expensive materials, such as stainless steel, or titanium or nickel alloys. These resist corrosion, but are still subject to scaling. In addition to restricting flow, the scaling then promotes pipe corrosion beneath it and is hard to clean. For heat exchangers used in binary plants—in which longer-lasting materials are particularly desirable—stainless steel and alloys also have lower heat conductivity, reducing the effectiveness of the exchangers.



With his materials composition and bonding expertise, and geothermal experience, BNL scientist Sugama was the ideal researcher to take on the challenge of making geothermal plant equipment last longer. Early on, he explored various cement linings for steel pipe, but didn't find them effective. In the mid-1990s, he turned to looking for the best polymer coatings for the job. (Plastic pipe and parts can be used in some geothermal and other corrosive environments, but not where there is high pressure or temperature, as is the case for most geothermal installations.) One polymer showed some promise, but then Sugama found that polyphenylenesulfide (PPS), which he had previously used for coating some military equipment, was the most resistant at high temperature and a highly effective choice as a coating for common carbon steel.

PPS is a 'thermoset' plastic, one that requires high temperature to form, and then takes on semi-crystalline structure. It can then withstand far higher temperatures than that at which it forms. It is highly resistant to oxidation, which means that it resists both corrosion and scaling. Whereas the oxide layer that protects stainless steel actually promotes scaling, very little will stick to PPS, and what little does washes off very easily. Unlike stainless and alloys, PPS-
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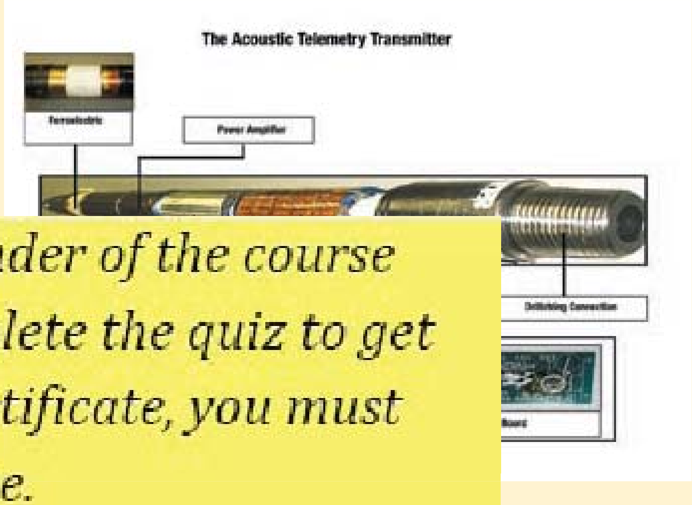
In particular, he expects to raise temperature tolerance above the 200ºC level frequently encountered in geothermal applications. At the same time, he is also exploring another promising polymer. Sugama clearly deserved his second R&D 100 Award in 2002, and PPS—already a commercial success—holds great promise as a standard for geothermal and other uses.

Sandia National Laboratories



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