Fluidized Beds at Utility Scale

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Cover: Clean coal combustion in the fluidized-bed of the Tennessee Valley Authority's 20-MW pilot plant near Paducah, Kentucky. Design and operation of the pilot plant has provided critical scale-up factors for the larger utility demonstrations now planned.

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FBC—A Commitment to the Future

Coal may have to provide up to 70% of the nation's total electricity generation by the end of this century. In the face of this growing reliance, the utility industry stands at a threshold of fundamental change in its technologic base for coal-fired generation. The present commercial technology is nearing the end of its development potential and is hard-pressed to respond to the rapidly changing requirements being placed on the industry. New options that can meet increasingly stringent siting and environmental demands and can be rapidly constructed in modular fashion over a range of unit sizes are particularly in demand.

One of the new technologies expected to help provide this capability is fluidized-bed combustion (FBC), a technique that is already well-applied in the industrial sector and will be in commercial demonstration on the scale of utility steam-generating units later this decade. As this month's cover story explains, FBC technology has matured in parallel with the growth of EPRI over the last 10 years, advancing from small engineering test and pilot-scale efforts to the full-scale projects that are now being implemented.

FBC's principal appeal is that it directly addresses the major factors affecting coal-fired power generation—notably, environmental controls. FBC tackles the pollutant emissions produced from burning coal precisely where they are formed—in the furnace. This approach is inherently less costly and more efficient than technologies that remove such pollutants from the flue gas. In addition, FBC reduces the sensitivity of boiler design and operation to fuel quality. This flexibility permits the user to operate in a buyer's market for fuel, thus substantially reducing operating costs.

The confidence with which FBC's commercial availability can be foreseen in the near term also provides an effective alternative for an industry facing the possibility of mandated additions of flue gas desulfurization systems to current coal-fired capacity. For example, proposed acid rain control requirements that would retrofit flue gas scrubbers on up to 100,000 MW of existing, high-sulfur coal-fired generating capacity would cost the nation at least $200 billion over the remaining life of the affected plants. This is equal to about half of the utility industry's net total plant assets today.

A more effective alternative would be the introduction of new, clean coal technologies, such as FBC, that offer greater emission control efficiency and improved generation productivity. If the $200 billion necessary to implement the scrubber retrofit strategy were instead spent for plants using advanced coal technologies, it would provide about half of the new generating capacity the nation is likely to require between now and 2015. Such an investment would at the same time provide superior environmental control, not only for sulfur dioxide but for nitrogen oxides and solid waste as well, while also improving the productivity and cost of power generation.

FBC technology also provides an option for addressing another critical need of an industry constrained by the high cost of capital for construction and uncertain demand growth—smaller unit sizes that can be built as modules in factories and brought on-line in less time to more closely follow lower growth rates. This can produce the equivalent of a 25% saving in capital investment. Compact pressurized-fluidized-bed plants promise such modularity without sacrificing the economies of scale of today's large plants. This approach to FBC may also be used to rapidly repower the latent capacity available in many existing steam turbines at a cost per kilowatt of one-half or less that for a new power plant.

The utility industry will face a major challenge in the 1990s to keep abreast of even modest growth in electricity demand. A successful strategy to meet this challenge will require the balanced contribution of new generating capacity, conservation and end-use management, and increased productivity from existing capacity.

EPRI has been pleased to serve as both a partner and a catalyst over the past decade in accelerating technical opportunities for resolving the new demands and uncertainties facing utilities. FBC is one of the major accomplishments of this sustained industry commitment.

Successful development and demonstration, however, is only part of the challenge in transferring such options as FBC to broad commercial application. Each utility should aggressively commit now to a comprehensive program that applies these options in the most cost-effective combination. Time is critical if the industry is to stay ahead of the events that are inevitably shaping the years ahead.

Kurt E. Yeager

Kurt E. Yeager, Vice President
Coal Combustion Systems Division

Authors and Articles

Clean combustion of coal, if thermally efficient as well, should be more economical and more dependable than any cleanup system that relies on exhaust gas filters and scrubbers for environmental compliance. That's the promise of fluidized-bed technology, mostly developed during the past 15 years and soon to be demonstrated for power generation by the electric utility industry. This month's lead article, **Achieving the Promise of FBC** (page 6), is by Taylor Moore, *Journal* senior feature writer, who draws extensively from the work of four research managers in EPRI's Fluidized Combustion Program.

Shelton Ehrlich, who heads the program, has specialized in fluidized-bed R&D since 1967. Before coming to EPRI in September 1975, he was with Pope, Evans & Robbins, Inc., for eight years as director of combustion research. Before that, he worked for four years as a nuclear engineer; and in still earlier work for Pope, Evans & Robbins, he was a project engineer on steam power plant betterment studies.

Callixtus Aulisio, an EPRI project manager since February 1978, also formerly worked for Pope, Evans & Robbins, first in the design of fluidized-bed units and later as engineering supervisor during the startup of a 30-MW demonstration at Rivesville, West Virginia.

Steven Drenker came to EPRI in August 1978 as a project manager and now focuses on R&D of pressurized fluidized-bed systems. He was formerly with Babcock & Wilcox Co. as a field service engineer for the startup of utility power plants and industrial process steam systems.

William Howe joined EPRI in August 1978 as a project manager. He came from Radian Corp., where he worked on the conceptual design of a 600-MW fluidized-bed boiler. Still earlier, he was with Pope, Evans & Robbins as part of the startup team for the Rivesville fluidized-bed demonstration.

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Easily seen in terms of new materials, machines, and apparatus, R&D results are difficult to comprehend when they remain in the abstract form of computerized analyses and mathematical simulations. **EPRI Software for Utility Needs** (page 16) describes the rapidly expanding effort to make EPRI computer codes available in consistent form for electric utility economists, planners, researchers, engineers, plant operators, and maintenance managers. Science writer John Douglas tells the story with information obtained principally from EPRI's Walter Esselman and Kathy Kaufman, but with details from software specialists in a number of EPRI divisions.

Esselman, director of engineering assessment and analysis, chairs the interdivisional Software Product Development Advisory Committee. Esselman has worked in EPRI's technology analysis and R&D planning since he came to the Institute on loan from Westinghouse Electric Co. in 1974; he has been a staff member since August 1975. Formerly with Westinghouse for 35 years, Esselman helped organize the Westinghouse Astronautics Laboratory in 1959, directed the company's Hanford Engineering Development Laboratory in the early 1970s, and thereafter was named to guide Westinghouse strategic planning for nuclear energy systems.

Kaufman was a secretary when she joined EPRI in March 1980, becoming an assistant to Esselman nearly a year later. As EPRI's software development and distribution coordinator, she also acts as staff to the interdivisional software committee. Kaufman's background includes a degree in law and professional work as a writer.

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Successful demonstration of a 45-MW binary-cycle geothermal power plant in southern California's Imperial Valley will double the size of the useful geothermal energy resource in the United States. **Heber: Key to Moderate-Temperature Geothermal Reserves** (page 24) is Nadine Lihach's account of this important resource and technology development. The *Journal*'s senior feature writer turned to EPRI's John Bigger for technical background.

Now manager for the Heber demonstration project, Bigger has been with the Geothermal Power Systems Program since January 1983. For nearly 7 years before that, he was a project manager for solar-thermal energy R&D. Bigger came to EPRI in May 1976 from the Los Angeles Depart. of Water & Power, where he had worked for 10 years, first in transmission design and construction and later in resource planning, with particular emphasis on waste heat, solar, and geothermal energy.

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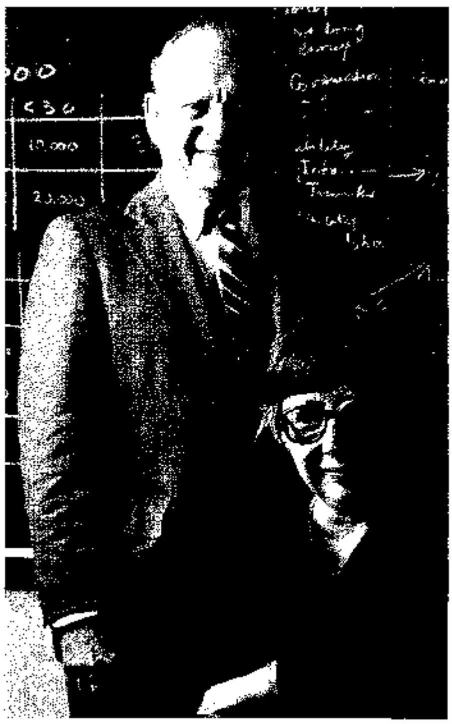
Subtle radio-frequency emanations from electric power machinery are turning out to be the telltales of specific phenomena, some of them precursors of equipment failure. **Advance Notice of Generator Failure** (page 30) reviews an EPRI-sponsored development and several adaptations conceived by utilities. The article was written by Nadine Lihach, aided by research managers of EPRI's Electrical Systems and Nuclear Power divisions.

James Edmonds is a project manager in the Plant Electrical Systems and Equipment Program, concerned with the phenomena and mechanisms of electrical and physical stress on generator rotors and related components. At EPRI since November 1978, he was formerly with American Electric Power Service Corp. from 1968 to 1977, ultimately as staff electrical engineer responsible for all rotating electrical machinery on the AEP system.

Gordon Shugars is a project manager in the Engineering and Operations Department of the Nuclear Power Division, specializing in methods and instruments for plant performance diagnosis. Shugars joined the Institute in September 1977 after three years with Bechtel Power Corp., where he held field and office positions in power plant design, construction, and testing. Earlier, he was in the Navy for five years, most of that time assigned to the Office of Naval Reactors.


Aulisio


Bigger

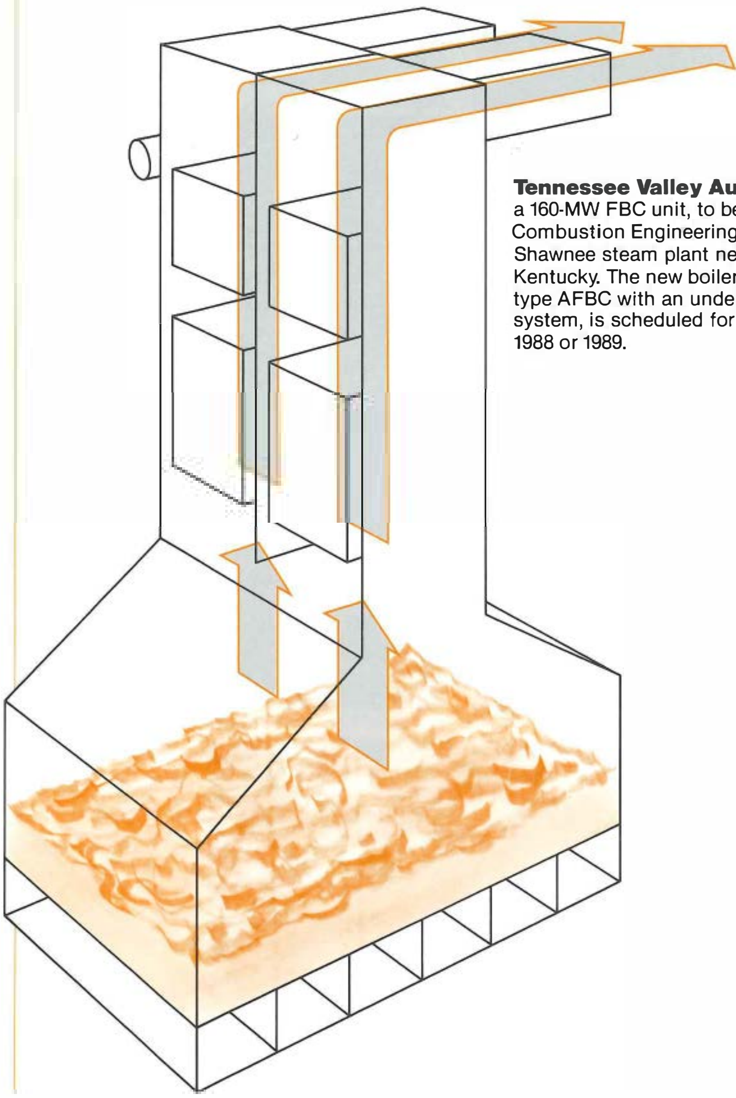

Esselman Kaufman


Shugars Edmonds

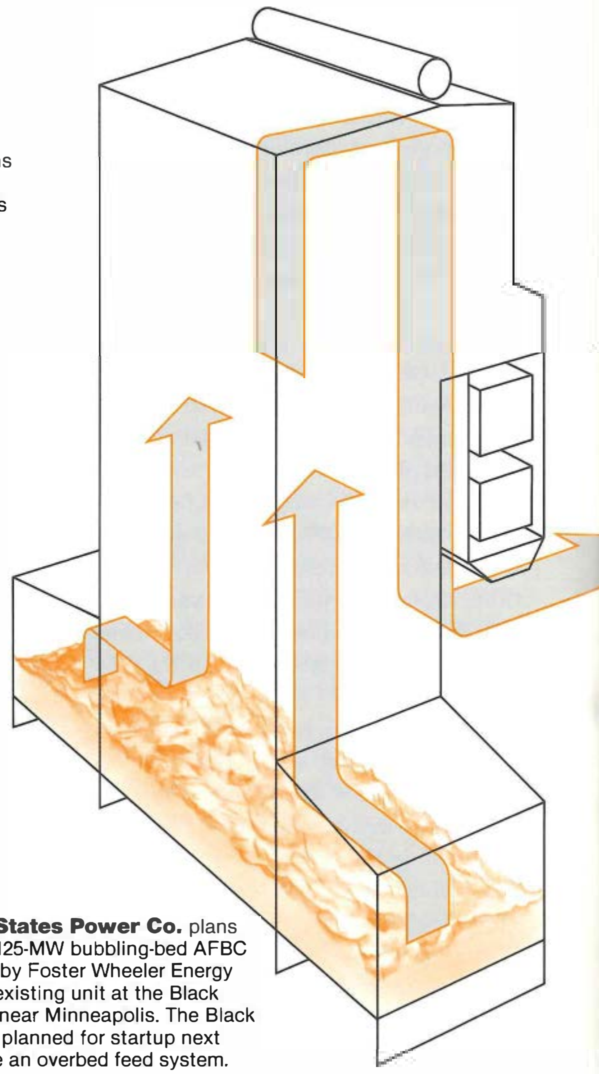

Ehrlich Drenker Howe

Achieving the Promise of FBC

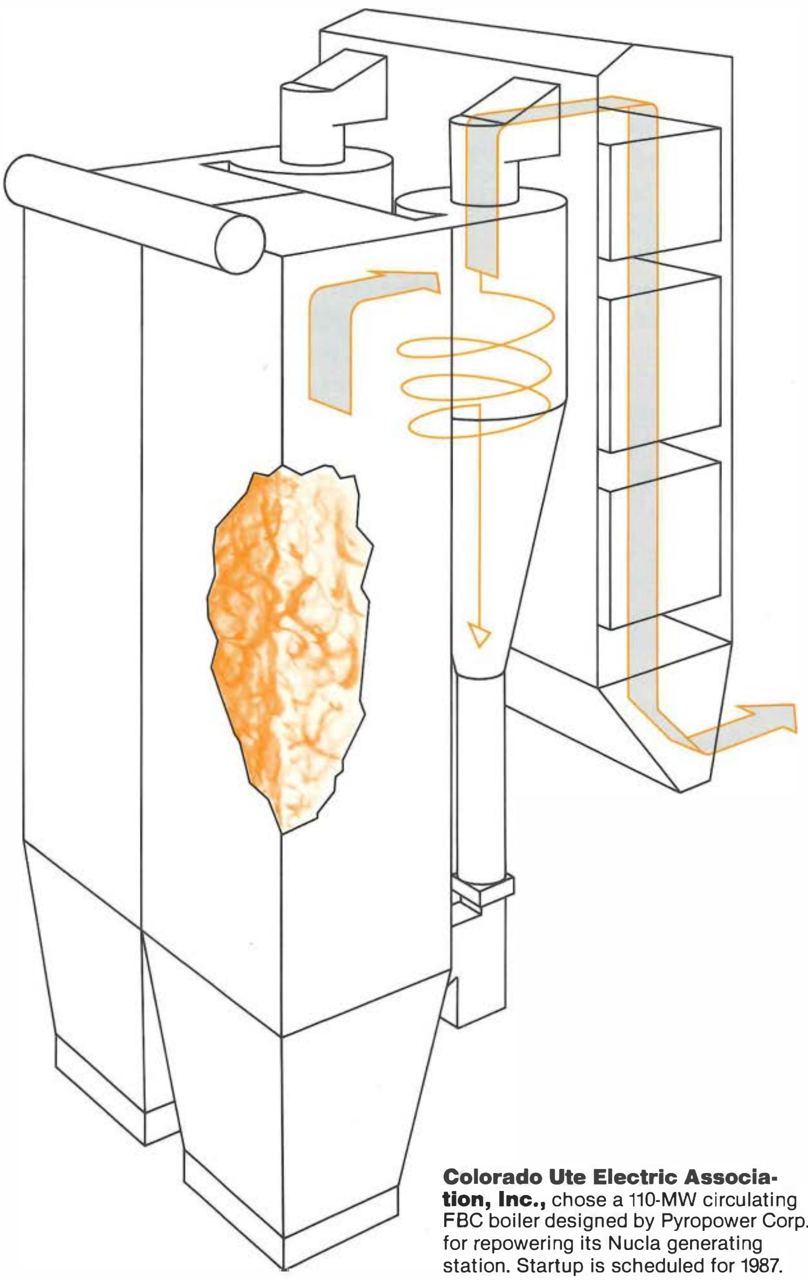
Already in wide use in other industries, fluidized-bed combustion (FBC) is achieving its promise as an environmentally acceptable successor to conventional coal-fired technology.



Tennessee Valley Authority plans a 160-MW FBC unit, to be built by Combustion Engineering, Inc., at TVA's Shawnee steam plant near Paducah, Kentucky. The new boiler, a bubbling-type AFBC with an underbed feed system, is scheduled for startup in 1988 or 1989.



Northern States Power Co. plans to retrofit a 125-MW bubbling-bed AFBC boiler made by Foster Wheeler Energy Corp. to an existing unit at the Black Dog station near Minneapolis. The Black Dog retrofit, planned for startup next year, will use an overbed feed system.



Colorado Ute Electric Association, Inc., chose a 110-MW circulating FBC boiler designed by Pyropower Corp. for repowering its Nucla generating station. Startup is scheduled for 1987.

Fifteen years ago, a few dozen research scientists and engineers gathered at Hueston Woods, Ohio, to hear exciting promises for the future of a technology that many believed represented the most significant innovation in coal combustion in over a century. The promise of fluidized-bed combustion (FBC) indeed seemed bright. By mixing coal with limestone and burning it as a suspended mass atop a cushion of air, the energy in coal of nearly any grade could be released with few of the troublesome pollutants and greater efficiency than obtained in conventional boilers. The prospect of a cheaper, cleaner way to burn coal appeared on the horizon as a saving grace for a fuel that was steadily declining in market appeal in competition with oil at $3/bbl.

Today, the economic context is dramatically different, but the promise of FBC has been largely achieved and its advantages confirmed. Fluidized-bed boilers are operating on coal, wood waste—and even municipal waste—in a variety of industries worldwide. In the United States, plans are being laid for the final phase of over a decade of intensive R&D aimed at demonstrating FBC technology on the scale of large utility steam generating plants. Three utilities, with EPRI support, have launched their own commercial demonstrations of FBC systems.

"When we look at the predictions that were made and compare them with where the technology stands today, we can definitely conclude that fluidized-bed combustion is achieving its promise," says Shelton Ehrlich, manager of FBC in the Coal Combustion Systems Division. "The pioneers didn't realize how tough it would be, how long it would take, and how much it would cost.

"Not all the predictions for FBC have yet been realized, and many of the cautions put forth then have proved to be on target," notes Ehrlich, "but fluidized-bed combustion is now an established steam-generating technique. Although EPRI's role in perfecting FBC technology for industrial-scale application has been limited to support R&D, its role in utility-scale application has been recognized as vital."

Before this decade is over, at least three utility boilers in the 100–200-MW capacity range will be in commercial operation, demonstrating FBC technology at a scale sufficient to confirm its role as one of the successors to conventional pulverized-coal-fired plants. Such a scale not only signals the realization of FBC's promise as a major generation expansion option for the future but also provides an option for meeting incremental utility capacity needs for the short term within the financial and environmental constraints now confronting the industry.

Redeeming the promise

For electric utilities, fluidized-bed combustion is a new technology, involving a different firing system than conventional pulverized-coal boilers. The concept of turbulent mixing of solid particles to accelerate reactions was taken up by the petroleum industry in the 1940s and 1950s to promote catalytic cracking of feedstocks.

In the early 1960s government energy research agencies in Britain and this country launched pilot plant projects that added a new twist to the fluidized bed: injection of limestone along with coal to react with and remove sulfur dioxide. Still, FBC technology remained little more than an engineering curiosity until the mid 1970s, when oil price shocks ushered in a new era that favored domestic resource development and increased sensitivity to the environmental impacts of energy conversion.

As Ehrlich recalls, enough was known about FBC in 1970 to prompt several experts to make some rather bold predictions about its future. The technology, they forecast, would have unprecedented fuel flexibility, high heat release rates, exceptional heat transfer, better combustion efficiency, reduced fouling and corrosion, high thermal storage for rapid load pickup, low emissions of sulfur and nitrogen oxides without expensive flue gas treatment, and the potential for compact, shop-assembled units.

The experts believed heat release rates of over one million Btu an hour per square foot of boiler cross-sectional area were achievable. And utility-scale systems of 1000-MW capacity with boiler efficiencies of over 90% were thought possible.

Based on these promises, EPRI undertook a step-by-step research program to develop utility-scale FBC. In 1977 EPRI built a 2-MW pilot plant that would simulate a 600-MW FBC boiler. "This was important because in the early 1970s there had been a couple of false starts with people short-circuiting the development process to exploit the oil crisis," Ehrlich remembers.

After the data at the 2-MW scale were fully evaluated, EPRI and TVA began design of a 20-MW pilot plant. "The people who discussed the promises of FBC in 1970 knew it would take a lot of hard work to redeem their promises," Ehrlich added.

Have the promises been realized in the intervening decade and a half? Not all of them, according to Ehrlich, but enough that FBC has reached commercial acceptance for both industrial and utility applications. Some 50 companies offer FBC boilers for sale in 25 countries; unit capacities range from 1 MW (th) to over 100 MW (th), and larger units, up to 480 MW (th), are being built in the United States and elsewhere. "Industrial-scale FBC boilers have made a real impact. Over 40 units are now operating or under construction in this country," reports Ehrlich, adding, "FBC has clearly achieved its promise in the industrial boiler field."

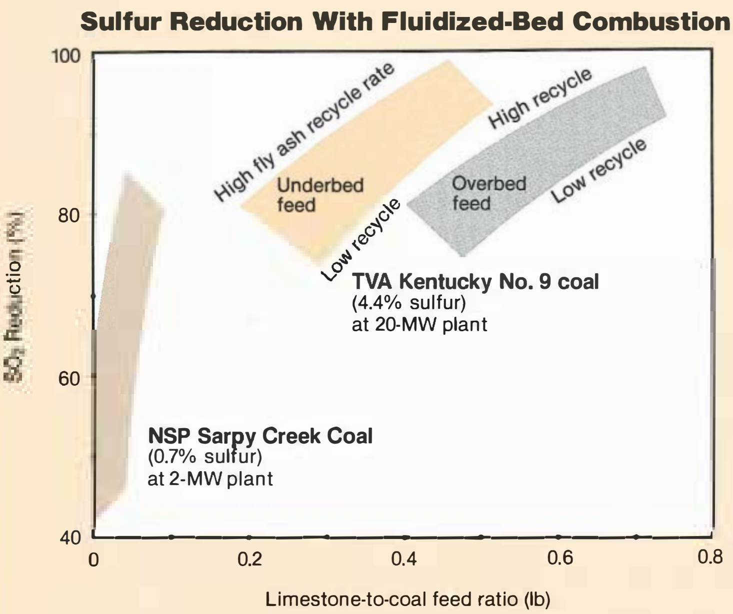
Utility-scale systems have advanced as well, although as Callixtus Aulisio, EPRI's manager for the world's largest FBC unit, points out, "We cannot yet design a 1000-MW FBC boiler that will achieve a thermal efficiency of over 90% on bituminous coal. We will, however, see a 160-MW unit with over 87% boiler efficiency operating on the Tennessee Valley Authority [TVA] system in less than five years. We found that increased residence time for gases and solids was needed to reach this level of performance. This was achieved by enlarging the furnace space over the bed and by recycling some of the particles that blew out of the bed. These concepts were brought to maturity in progressively larger pilot plants. And our experience operating progressively larger prototype units shows performance improving with size."

Most of the early forecasts for FBC have been realized through the comprehensive pilot development program for utility-scale systems. Current FBC designs include about 10–15% more heat transfer surface area than a comparable conventional boiler—the result, not of a technical difference, but rather, according to Aulisio, of "a natural conservatism by manufacturers when a first-of-a-kind boiler is tendered with strict performance guarantees." FBC superheater sections, constructed of costly stainless steel, average 24% less area than those in conventional boilers, however.

To limit pollutant emissions and maintain high boiler efficiency, FBC units must operate within a narrow temperature range (1500–1600°F; 816–871°C), making load turndown difficult. This was the focus of a major development effort that resulted in load-following capability at least equivalent to that of a conventional plant. In addition, the heat retained in the bed permits startup directly on coal after overnight shutdown. This should enhance the cycling capability of FBC.

Particulate emissions control also presents a challenge; electrostatic precipitators (ESPs) have a harder time cap-

The amount of sulfur that can be retained during fluidized-bed combustion depends on the ratio of limestone sorbent to feed coal, as well as on the specific coal that is burned. This graph indicates sulfur reduction levels achieved in tests at both the EPRI 2-MW FBC test facility and the TVA–EPRI 20-MW pilot plant. A low-sulfur subbituminous coal was tested for Northern States Power Co. in the 20-MW plant; high-sulfur Kentucky No. 9 coal was burned at the 20-MW plant, using two different coal feed systems. The bands show that higher fly ash recycle rates improve sulfur reduction.



FBC's Fuel Flexibility

Fluidized-bed combustion offers unprecedented flexibility in the choice of fuel that can be fired, including coals of high ash and sulfur content. Listed are low-grade fuels considered for use in commercial FBC boilers that have been successfully test-fired in pilot plants.

Anthracite culm	Tree bark
Coke breeze	Cow manure
Industrial sludge	Lignite
Oil shale	Peat
Petroleum coke	Sewage sludge (dry)

turing FBC dust because it has higher electrical resistivity than dust from burning pulverized coal. To the extent that early utility experience with FBC involves conversion of existing boilers that already use ESPs, FBC retrofit with ESPs will continue to command R&D attention. Baghouses will normally be used on new units, however.

The method by which coal and limestone sorbent are introduced in the boiler is a major area of engineering focus. "It has always been the make-or-break issue," explains William Howe, who has been responsible for 2-MW and 20-MW pilot plants where solutions were sought and found. Both underbed and overbed feed systems have been developed and tested. The underbed approach forces coal and limestone in several streams under pressure through the bottom of the boiler; overbed feed uses spreader-stokers to throw the coal over the top of the bed, where furnace pressure is neutral.

Both approaches have their advantages and drawbacks. Underbed feeding is susceptible to plugging, while overbed systems may require a means of controlling the coal fines to maintain comparable combustion efficiency with coals of lower reactivity. "Both types have been tested in FBC pilot plants and both will be given the final test in the upcoming utility demonstration projects," adds Howe.

A winning score

Most of the early promises have turned up on the plus side of the FBC R&D scorecard. Pilot tests have confirmed remarkably little fouling or corrosion in the furnace. Fuels of such low quality as coal waste, cow manure, sewage sludge, and tree bark have been successfully test-fired, confirming the promise of unprecedented fuel flexibility. The number of coal and sorbent feed points required in an FBC boiler has been steadily reduced. And research has proved that the energy stored in a hot fluidized bed permits rapid and trouble-free load increases.

Limestone sorbent has been shown very effective in capturing sulfur dioxide as dry waste, eliminating over 90% in combustion. Efforts to reduce the sorbent-to-sulfur ratio to the minimum effective level continue because of the effect of limestone costs on overall plant economics. Sorbent requirements have been reduced through an improved understanding of sulfur capture by limestone, but the best wet scrubbers on pulverized-coal plants can remove equal amounts of sulfur with about half the raw limestone.

Unlike FBC sorbent injection, however, wet scrubbers entail substantial maintenance costs and operating efficiency penalties, and they produce a wet sludge that presents disposal problems. FBC systems also generate large amounts of spent sorbent as waste, but the material is dry and disposal is thus simpler and cheaper. FBC waste is proving useful as a construction aggregate and agricultural fertilizer.

The mechanism by which nitrogen oxides are formed in an FBC boiler is similar to that in a pulverized-coal boiler—as a function of the coal type, excess air, and temperature. But the lower combustion temperatures in an FBC boiler inherently limit NO_x formation. Pilot tests at the 20-MW scale show NO_x levels well below the U.S. Environmental Protection Agency's New Source Performance Standards. Two-stage FBC firing offers the potential of even lower NO_x emissions. Howe comments, "Late last year, in tests cosponsored with Consolidated Edison Co. of New York, we achieved NO_x levels of about one-third the EPA standard, and we get regular reports from our friends in Japan showing even lower NO_x values with two-stage air addition."

Recycling fly ash is the major factor influencing carbon combustion; efficiencies approaching 99% can be achieved at recycle ratios of 2:1. An innovation

FLUIDIZED BED UNDER PRESSURE

The fuel flexibility, internalized emissions control, and higher heat transfer of FBC open the way for packaging a power plant in small (150–250-MW), compact designs that could be shop-fabricated, shipped by barge, and installed as incremental capacity to closely match a utility's load growth.

In response to industry interest in modular plants, EPRI is supporting development of a type of fluidized bed in which the furnace is pressurized to 1.0–1.5 MPa, or 10–15 atm. PFBC promises shorter construction time and the lowest busbar energy cost of any coal-fired power generation option now under development.

Until recently most conceptual designs for PFBC focused on high-temperature, combined-cycle operation, in which the hot (1500°F; 816°C) gases from the boiler are used to drive a gas turbine before passing through a waste heat steam generator to run a conventional steam turbine cycle. This approach, however, may require development of new gas cleanup technology because of the potential for the high-temperature flue gas to foul and corrode the gas turbine.

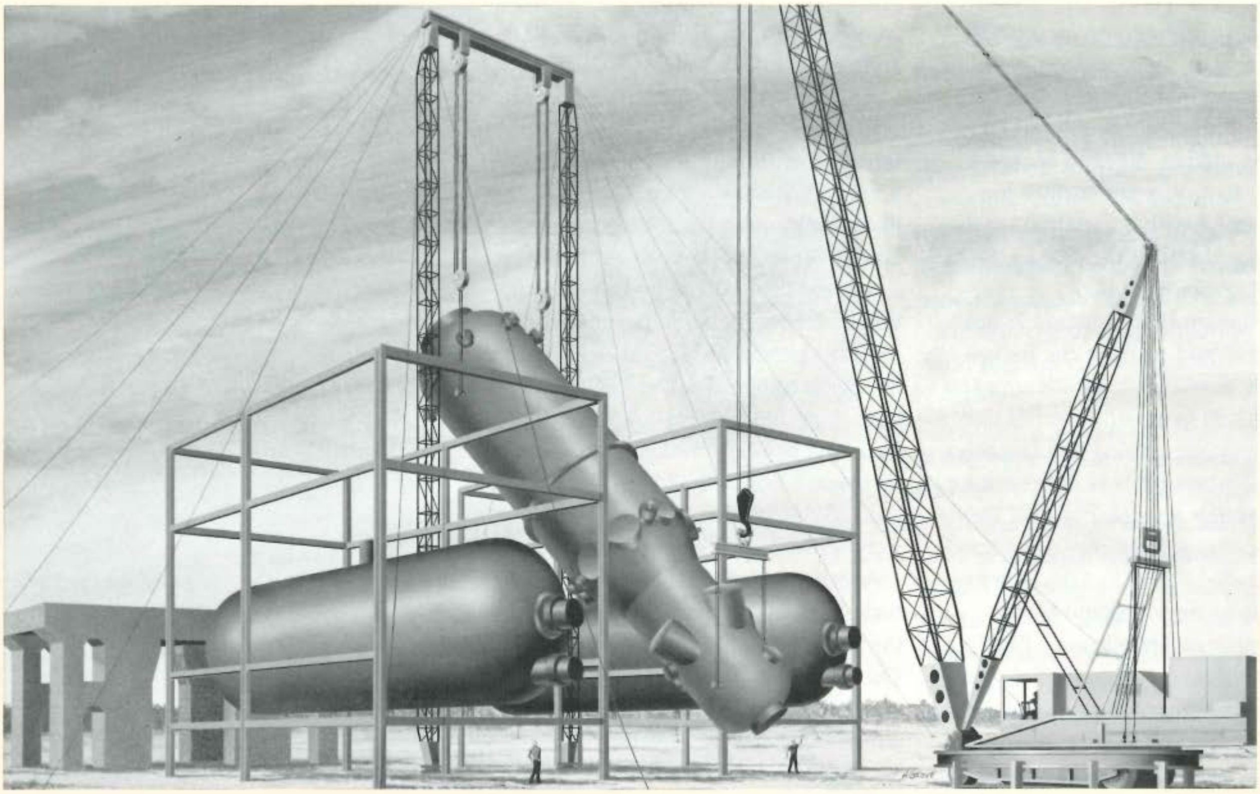
Another PFBC approach identified in an EPRI study by Brown Boveri Corp. cools the gas in a convection pass above the fluidized bed to about 800°F (427°C) before it enters the gas turbine. The lower inlet temperature allows the adaptation of state-of-the-art particulate removal systems (ESP or baghouse) to minimize gas turbine blade erosion and the need for high-temperature piping. Power from the gas turbine is used only to drive the boiler's air compressor, while a conventional steam cycle generates all the electricity for transmission.

The projected overall system efficiency of such a turbocharged PFBC is 37%—about 2% less than combined-cycle PFBC. But the turbocharged PFBC's lower technical risk, greater expected reliability and availability, reduced capital cost, and earlier expected commercial availability make it a more-attractive near-term alternative to combined-cycle operation. EPRI is sponsoring a design and cost estimation study of a modular 250-MW turbocharged boiler that when completed early this year should provide a confident basis for comparing capital costs of a four-unit turbocharged PFBC plant with a conventional 1000-MW pulverized-coal plant with flue gas scrubbers. Project participants include Brown Boveri; boilermakers Foster Wheeler Energy Corp. and Combustion Engineering, Inc., plus Lurgi Corp.; Research-Cottrell, Inc.; and Fluor Engineers, Inc.

Considerable R&D is still required before the commercial potential of turbocharged PFBCs can be realized. EPRI's effort has emphasized materials evaluation and hot gas cleanup, as well as development of a design base for the heat transfer tube bundle within the pressurized bed.

The principal engineering development facility for PFBC R&D in the years ahead is the 25-MW (equivalent) test rig at Grimethorpe, England. Supported, until recently, by the federal energy agencies of the United Kingdom, United States, and West Germany, activity at Grimethorpe will continue under sponsorship of England's National Coal Board and the Central Electricity Generating Board, with some support from EPRI and DOE.

The Institute has dedicated substantial funding support over the next three years for a number of test



programs at Grimethorpe, including high-temperature in-bed tube erosion studies, advanced hot-gas filter tests, and continuing materials evaluation for high-temperature gas turbines.

In recent years several utilities have indicated particular interest in PFBC. One of them, American Electric Power Co. (AEP), is working with ASEA PFBC Ab (a European joint venture) to develop a combined-cycle PFBC system. ASEA PFBC operates a 15-MW (th) pilot plant in Malmo, Sweden. Positive results from testing there could lead to a realization of AEP's plan to build and operate a 70-MW combined-cycle demonstration plant by 1990.

Florida Power & Light Co. (FP&L) has evaluated the turbocharged PFBC for repowering a retired 80-MW oil-fired unit at its Palatka station near Jacksonville. The EPRI-sponsored study, which included General Electric Co. and Babcock & Wilcox Co. as participants, concluded the project could be built for about $51 million ($660/kW), not counting certain first-time design and test costs. Results have led to follow-on sorbent and boiler tube erosion tests by FP&L in England at the National Coal Board's Leatherhead laboratory, as well as expanded experiments by General Electric on gas cleanup technology.

In addition, in 1984 FP&L commissioned Sargent & Lundy to do an engineering design and cost assessment of a new 800-MW turbocharged PFBC plant at FP&L's Martin County generating station. The assessment is based on initial construction of a steam turbine generator unit of 800-MW capacity, with phased construction of four 200-MW turbocharged boilers over a period of several years. Studies have indicated that such an approach yields certain cash-flow benefits, as well as capital construction costs 10–15% less than for equivalent pulverized-coal capacity with flue gas desulfurization.

Because of its lower expected unit cost and shorter construction lead time, EPRI believes the turbocharged PFBC to be an end in itself for near-term utility application of FBC technology. But successful development of this approach could help pave the way for the ultimate FBC development, one that has long been a goal of power engineers: a highly efficient, direct coal-fired combined-cycle system. □

developed in the United States and now applied in Japan reduces the degree of fly ash recycle required for high efficiency by providing additional furnace area for carbon burnup. The concept appears applicable to larger FBC designs.

The promise that fluidized-bed boilers could achieve energy release rates of over one million (10^6) Btu an hour per square foot of boiler surface has been redeemed with a variation on the classic atmospheric FBC design known as circulating fluidized bed.

The prediction that fluidized-bed development would provide the necessary technical stimulus for advanced, highly efficient generating plants that could be shop-assembled and installed as small, compact units is approaching fruition through a variant of FBC technology known as pressurized-fluidized-bed combustion (PFBC). Although not as far along in development as the atmospheric-type FBC design, PFBC designs could lead to the ultimate potential FBC development: a direct, coal-fired combined-cycle system operating at advanced steam temperature and pressure conditions.

Utilities take the plunge

Conversion of existing industrial or utility coal boilers to fluidized-bed designs was seen by the prognosticators at Hueston Woods as an attractive first-generation application of the fledgling technology. The first effective industrial boiler conversion was of a 13.5-MW (th) unit in 1975 at Renfrew, Scotland, by British Babcock Limited. This conversion was successful as a pioneer test and development effort.

The first electric utility retrofit of FBC was made in 1981 at a 15-MW unit at Northern States Power Co.'s French Island station in Wisconsin. Built in 1948 to burn coal but later converted to oil-firing, the unit now operates with FBC on low-cost waste wood. An experimental test-firing of shredded solid waste in 1983 was a modest success despite the lack of a nearby source of the fuel. NSP has proposed to build a refuse-derived fuel (RDF) plant nearby and retrofit a second 15-MW unit at French Island with FBC. Both units would then burn a blend of 25% RDF and 75% waste wood.

NSP, EPRI, and other project participants have now joined forces to retrofit a much larger unit with FBC—a 100-MW pulverized-coal boiler at the Black Dog power plant near Minneapolis. When the 30-year-old boiler is converted to fluidized bed, it can continue burning the subbituminous coal that had previously forced derating of the boiler to 85 MW. The FBC conversion, expected to be operational next year, will not only recapture the lost megawatts but will add another 25 MW. Foster Wheeler Energy Corp. is designing the Black Dog FBC boiler.

According to Ehrlich, several factors make the Black Dog project ideal as the first large-scale conversion to FBC. There is strong community support, including that of environmentalists; uprating the boiler by 25 MW will account for only a fraction of the overall $50 million project cost; related improvements to extend the boiler life will allow full recovery of the new investment; the unit will burn 100% subbituminous coal while meeting federal New Source Performance Standards for both SO_2 and NO_x; and the FBC furnace will fit well within the existing space.

To meet a stringent particulate emission standard (0.04 lb/10^6 Btu), NSP plans to modernize the existing ESP and limit flue gas volume by cooling the gas and controlling air preheater leakage. EPRI will sponsor a $3.5 million planned test and documentation program for the boiler conversion.

"Conversion of Unit 2 at the Black Dog plant from pulverized coal to AFBC operation should provide a technical and economic basis for responding to the acid rain issue in the upper Midwest," comments Jerry Zylkowski, NSP's project manager for the Black Dog conversion. "The key issues for us were the ability, with FBC, to burn a high-fouling coal, to increase existing capacity, and to extend the life of the plant."

Judging from the factors that make the Black Dog project an ideal retrofit application, EPRI believes there are many other similar opportunities where environmental requirements, power plant life extension, and increased boiler capacity are high priorities. On the basis of a screening survey of units ordered between 1945 and 1965 and sized between 30 and 300 MW with heat release rates under 1.5 million Btu an hour per square foot of plan area, EPRI estimates about 200 pulverized-coal boilers in the United States are candidates for FBC retrofit, representing an aggregate generating capacity of 20,000 MW. Some of these boilers may be more difficult to convert than Black Dog, but they will have the benefit of NSP's experience.

In 1970 optimism about FBC was so high it was even thought that large numbers of operating boilers would be replaced with new fluidized-bed boilers because of the high cost of retrofitting those conventional plants with wet scrubbers to meet emissions limits. "Today it does not seem likely that wholesale replacement will be the general case," says Ehrlich, "but the largest of the three planned utility FBC demonstrations follows precisely the approach predicted—it will replace a pulverized-coal boiler that has been operating since 1955 with a new FBC boiler."

This is the $220 million FBC demonstration planned by TVA, Duke Power Co., the state of Kentucky, and EPRI at TVA's Shawnee steam plant near Paducah, Kentucky. Combustion Engineering, Inc., will supply the new 160-MW FBC boiler, which will be installed adjacent to the existing Shawnee power house, replacing one of ten 1950s-vintage pulverized-coal boilers. EPRI has committed up to $75 million

More than 40 small fluidized-bed boilers are being used for industrial applications in a number of industries. Shown is a Pyropower Corp. unit recently installed at California Portland Cement Co.'s Colton plant.

for the first-of-a-kind technical and economic risks of the project, including $20 million for a 10-year test program. The new FBC boiler is expected to be placed in service in 1989.

A key factor in TVA's decision to replace a boiler that has given good service for 20 years with a new FBC design is the fuel flexibility offered by fluidized bed. To meet environmental emissions limits, TVA recently switched the Shawnee units to a higher-cost, low-sulfur coal instead of the locally mined, high-sulfur coal. The ability to burn high-sulfur coal in the FBC boiler could mean a very substantial fuel cost reduction.

According to Michael High, director of the federal utility's Division of Energy Demonstration and Technology, "TVA had counted on nuclear power to meet virtually all future load growth. Now, it looks as if our next large unit will be an FBC boiler. The 160-MW demonstration is the key to proving that FBC is reliable in utility-scale applications, as well as efficient and clean."

The TVA project represents the concluding phase of a development program that has progressed from engineering test and pilot facilities to the current full-scale demonstrations. The effort on large-scale FBC began with construction and limited operation of a 30-MW AFBC boiler at Rivesville, Virginia, under DOE sponsorship in the mid 1970s. This plant highlighted key concerns for utility application but was shut down in 1979 and later dismantled.

The 160-MW FBC plant will join a 20-MW TVA FBC pilot plant that has operated at the Shawnee station since 1982. A four-year TVA–EPRI test plan at the 20-MW pilot continues with performance evaluations of full-scale FBC components and auxiliary equipment, load control approaches, and coal feeding methods. Design of the 160-MW unit is intended to fully apply the engineering experience gained from the pilot plant.

EPRI's FBC effort also continues to

make use of a 2-MW process development facility at Babcock & Wilcox Co.'s Alliance (Ohio) Research Center. Funded by EPRI and completed in 1977, the 2-MW plant has provided critical input to the design of both the 20-MW and 160-MW facilities. Insights resulting from the 2-MW scale include the addition of a fly ash recycle system for greater combustion efficiency.

A different type of atmospheric FBC design that has found wide acceptance in the industrial boiler field will also be in utility-scale demonstration by decade's end. Colorado Ute Electric Association, Inc., plans to install a 110-MW circulating fluidized-bed combustion (CFBC) boiler at its Nucla generating station.

In a CFBC design the fluidizing air velocity is typically 20 ft/s (6 m/s), twice that of the conventional bubbling-type AFBC. A dust collector yields a solids recirculation rate of over 99%, promising improved carbon burnup, greater NO_x reduction, and reduced limestone requirements.

EPRI and Colorado Ute cosponsored a design study for the Nucla CFBC. Colorado Ute selected Pyropower Corp., which uses a design developed in Finland by Ahlstrom Co., to supply the new boiler. The 25-year-old Nucla plant's generating capacity will be increased from 36 MW; its three stoker-fired coal boilers have already been retired because of high operating and maintenance costs.

The utility determined that the $86 million CFBC retrofit could be accomplished at about one-third the capital cost of building new pulverized-coal capacity. The difference, however, does not reflect the existing general plant equipment and site costs that would be associated with an entirely new FBC construction project.

"Our existing 36-MW plant at Nucla was too expensive to keep in service, but we needed a source of power at that point in our system—the next closest plant is 300 miles away," ac-

SCALING UP FBC: A CASE STUDY

The technical basis for many of the design features of utility FBC demonstration projects now planned grew from insights gained in operating progressively larger engineering units. These include the EPRI 2-MW, 6-by-6-ft process development facility built in 1977 and the TVA–EPRI 20-MW pilot plant completed in 1982. The selection of coal feeding systems for the 160-MW TVA and 125-MW Northern States Power Co. (NSP) demonstrations illustrates the value of a substantial process and reliability data base in assessing various design trade-offs.

A major area of engineering development with FBC focused on evaluation of the two current options for feeding coal into the boiler: a pneumatic underbed feed system and a mechanical overbed coal spreader. Despite a simplicity of design that should result in high reliability for the overbed system, there has been concern that this might be offset by performance penalties associated with combustion efficiency losses and increased limestone sorbent requirements.

To assess these trade-offs, design coals for the TVA and NSP demonstrations were tested in both overbed and underbed feed systems. High-sulfur Kentucky No. 9 coal for the TVA demonstration was tested on the 20-MW plant, while a Wyoming subbituminous coal was tested for NSP on the 6-by-6-ft facility. Data from these tests were applied in evaluating designs for the TVA and NSP projects last year; economic penalties were assigned to plant costs for process performance and reliability as a result.

Although comparable combustion efficiency was achieved with the two feed methods once enough fly ash recycle was established, sulfur capture efficiency was significantly impaired for the Kentucky No. 9 coal during overbed feed tests because of the substantial release of SO_2 in the freeboard above the fluidized bed. In addition, variability in the amount of the coal fines (particles of less than 500 μm in diameter) and problems with ash accumulation required washed coal for the overbed tests.

For NSP's subbituminous coal, however, there was no difference in sulfur capture efficiency between the overbed and underbed systems, nor were there problems with rocks or fines.

One conclusion from the tests was that for an overbed system to be economical with the Kentucky No. 9 coal, the coal preparation system should be designed to control rocks and fines. Two such coal preparation schemes were evaluated by TVA; both included complicated features. But a reliability assessment using the EPRI-developed UNIRAM model, based on equipment outage data from the 20-MW plant and other facilities, showed that the integrated overbed coal preparation and feed system would be less reliable than the underbed feed system that TVA later selected.

Thus, while overbed systems may initially appear to be the simplest and most reliable FBC feeding method, selection of the best method for a specific application must take into account coal properties, combustion and sulfur capture efficiency, and the feed system's overall reliability when integrated with coal preparation. □

cording to Theodore Rosiak, executive assistant to the president of Colorado Ute and manager of the Nucla FBC project. "We bought a 110-MW fluidized-bed boiler and are uprating our old plant—all for about $840/kW. We think it's a good idea for our customers, but we also think that we and EPRI can help the vendors scale up the technology to meet our needs for larger units in the 1990s."

Colorado Ute and Pyropower plan to join with EPRI in a comprehensive test program to explore scale factors and determine whether cost-effective CFBC plants at the 500-MW scale and greater can be designed. The program will address key technical uncertainties associated with scale, including horsepower requirements, process performance, startup and transient operation, and overall reliability.

FBC economics

Completion of the three key utility demonstration projects will represent a major step toward establishment of the technical, performance, and economic basis for confident large-scale application of FBC as a commercially competitive technology. It is unrealistic to expect that any new generation technology will supersede conventional pulverized-coal plants overnight. Rather, FBC development has reached the point where it is at least competitive in performance and shows specific advantages in first-generation applications.

For example, the opportunities to eliminate the wet scrubbers associated with conventional plants and to build more-economic, smaller generating units with FBC remain important cost and operational advantages of the first-generation FBC demonstrations.

The levelized cost of electricity from fluidized-bed plants still promises to be about 10% less than that from conventional coal-fired generation because of the influence of another major component of total cost: fuel. As the TVA demonstration project suggests, the economic difference between the flexibility to burn high-sulfur coal—or virtually any other fuel—and the requirement to fire more-expensive low-sulfur coal can tip the balance in FBC's favor, depending on site-specific factors.

It appears likely, given the utility industry's present financial constraints and FBC technology's economic status, that a utility's decision on whether to adopt FBC will be favorable when conditions resemble those that applied to the three planned FBC demonstrations: the need to increase capacity and extend the life of existing plants, and the need to burn lower-cost fuels without adding flue gas desulfurization systems while still complying with environmental regulations.

"Perhaps most important, as a newly developed technology, FBC has the potential for continued refinement of these advantages as its commercial application matures," comments Kurt Yeager, EPRI vice president and director of the Coal Combustion Systems Division. "In contrast, conventional technology is nearing the end of its development potential. Building any kind of power plant today is expensive and constrained by the high cost of capital, so not many plants are being built. FBC is an option with the potential to fundamentally change the role of utilities in today's fuel market. FBC's insensitivity to fuel type allows utilities to operate more in a buyer's market than in a seller's market; they can easily switch fuels, depending on availability and price, without regard for fuel quality. Thus, they're not locked into one type of coal because of emissions limits."

An enduring promise

FBC has matured as a utility generating technology somewhat in parallel with the growth of EPRI over the last decade. And according to Yeager, the industry can take a lot of credit for that. "The technology would not be where it is today had not the utility industry, with EPRI, made the commitment, brought in people with the needed expertise, and had the patience and persistence to carry it through the development cycle. Through EPRI, the industry has carefully advanced FBC—it hasn't oversold the technology, and it hasn't tried to make it commercial before its time.

"But we're now at the point where FBC is being seriously considered for commercial application," adds Yeager. "The confidence that has been gained in the operation of the 20-MW pilot unit in the last two years, and now the beginning of the demonstration phase, has already led to a commitment by several utilities to commercially apply FBC. When these demonstration projects are completed, FBC systems will stand as one of the keystones of advanced coal technology that will permit utilities to rely on the nation's abundant coal resources long into the future in an environmentally acceptable manner while also improving the productivity and lowering the cost of power generation." ■

Further reading

S. Drenker and R. Fancher. "Electricity Rate Effects of 150-MW Shop-Assembled, Turbocharged Boiler Generating Units." *Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, Vol. 4,* held in San Francisco, August 1984.

S. Ehrlich, C. Aulisio, W. Howe, and S. Drenker. "Fluidized-Bed Combustion for Utility Applications—Status Report." Paper presented at a meeting of the Power Generation Committee, Association of Edison Illuminating Companies, held in Phoenix, Arizona, April 1984.

Campaign II Interim Report, Technical Summary. Interim report for TVA–EPRI 20-MW AFBC Pilot Plant Test Program. December 1983. Knoxville, Tenn.: Tennessee Valley Authority.

6- × 6-ft Atmospheric Fluidized-Bed Combustion Development Facility and Commercial Utility AFBC Design Assessment. Interim report for RP718-2, prepared by Babcock & Wilcox Co., March 1983. EPRI CS-2930.

This article was written by Taylor Moore. Technical background information was provided by Shelton Ehrlich, Steven Drenker, William Howe, and Callixtus Aulisio, Coal Combustion Systems Division.

EPRI Software for Utility Needs

In response to a growing need for software in utility operations, EPRI is working with the industry to ensure the quality and usability of its computer codes.

Software development for the electric power industry has accelerated greatly in recent years as new computer technology has become available and utilities have required new analytic tools for coping with vast quantities of data. In response to utility needs for new codes, EPRI's role in developing software for electric power applications is growing rapidly. Over the last two years the number of EPRI codes available to member utilities has more than doubled, and the rate of licensing and distribution of these codes has expanded at least as rapidly.

In addition, an increasing proportion of EPRI's R&D results are now being made available to utilities in the form of software. Computer codes make new knowledge available in a way that utilities can use most easily. When new techniques or results of experiments, tests, and analytic studies are made available as reports or data bases, much time can elapse before they are put into practice. Incorporating such information into a computer code, however, accelerates technology transfer.

Development of sophisticated software means that utilities are better able to use the latest computer technology for meeting a variety of practical needs. Applications range from nuclear reactor design to automated plant operations and economic projections. "You can't run a modern, large electric utility without a significant amount of software," says Thomas Bishop, manager of the Engineering and Scientific Systems Division of Pennsylvania Power & Light Co. and a member of the EEI Engineering and Operations Computer Committee. "There's a need for a tremendous amount of computing tools in a host of areas—commercial, scientific, and forecasting."

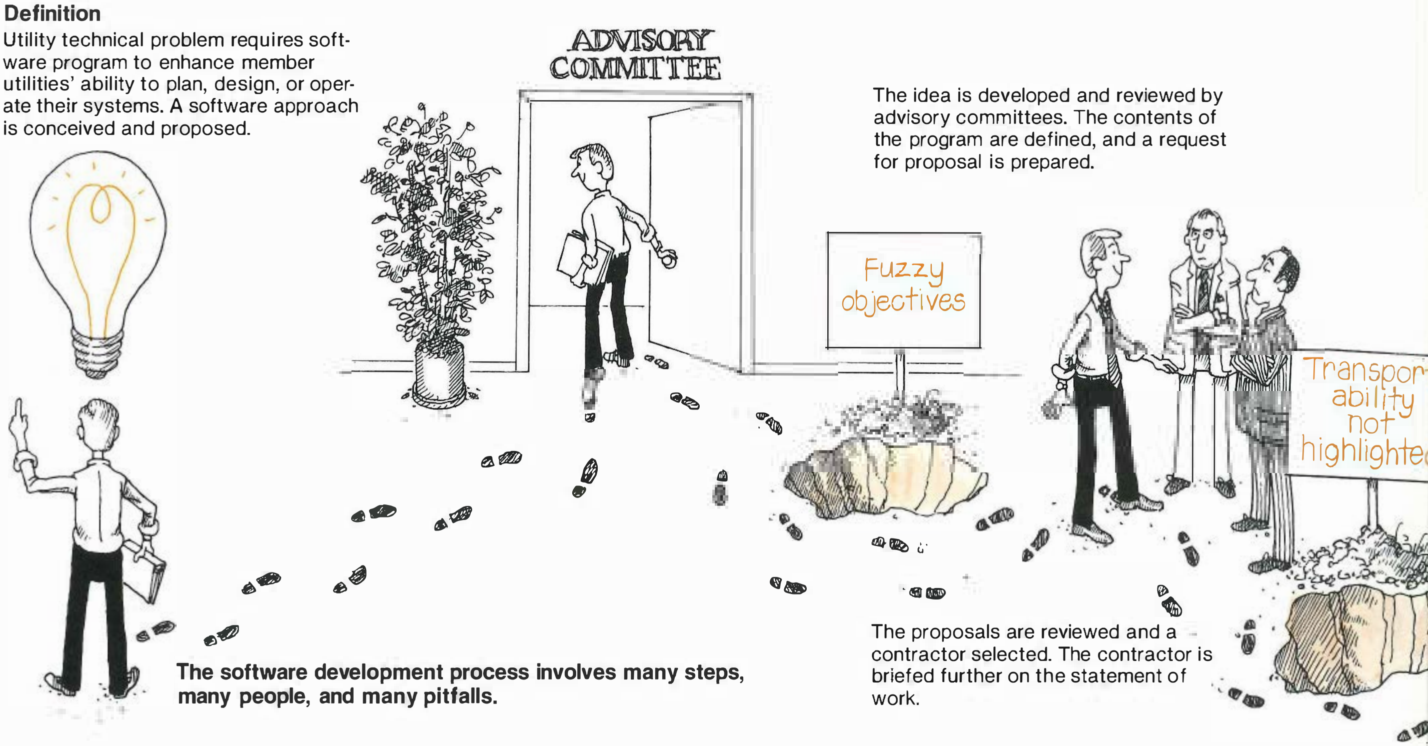
To make sure that new codes adequately meet utility needs, EPRI's senior management has instituted a series of initiatives to formalize various software responsibilities. EPRI established an interdivisional committee in 1982 to facilitate communication about software around the Institute. Basic software policies have been published to ensure consistent quality of EPRI codes. A new center for verifying, distributing, and supporting the installation of codes has been established. And new ways are being explored to improve code maintenance and enhancement through utility user groups and cross-licensing agreements with software vendors.

"We're taking a team approach," explains Walter Esselman, director of Engineering Assessment and Analysis. "EPRI and the utilities are combining their talents to develop a significant number of useful software packages. Important utility contributions are made at each step of code development. The utility advisory structure is involved in the initial decision to create a new code. An industry task force then works with the project manager in defining objectives for the code. Finally, before a code is released, its usefulness must be demonstrated by a group of utilities—usually 6 to 15 utilities—on their own computer systems."

The software challenge

Developing large computer codes is an expensive, tedious business. Electric power system codes tend to be highly specialized and thus require highly labor-intensive, custom programming. Because a typical code requires several years to develop, a team approach between utility advisers and EPRI staff is essential to make sure it will provide

Definition
Utility technical problem requires software program to enhance member utilities' ability to plan, design, or operate their systems. A software approach is conceived and proposed.



The idea is developed and reviewed by advisory committees. The contents of the program are defined, and a request for proposal is prepared.

The proposals are reviewed and a contractor selected. The contractor is briefed further on the statement of work.

The software development process involves many steps, many people, and many pitfalls.

practical utility use. Extensive tests must be made against experimental data, and demonstration of the code in a utility environment usually requires several months of effort.

Because software development is so complex, the spectacular growth of EPRI codes has not come without problems. Initially, software was treated like other products of R&D, with policies and procedures left up to each division. This meant that no uniform requirements were established for a production-grade code—that is, one ready for general distribution and immediate use. There was concern that a utility might order a new EPRI code only to find out that the code would not work on its particular kind of computer or that the code would not solve its particular engineering problems. The degree of testing and validation varied widely among individual codes. Documentation was not standardized. Provision for code maintenance was irregular, and the previous distribution center could not provide adequate support for code installation.

The requirements of the EPRI software development and distribution systems are unique. Codes must be thoroughly tested, and feedback from users must be incorporated continually to correct errors and make codes easier to use. For some codes, new information must be periodically inserted to keep them up to date. Documentation must be accurate and clearly written to satisfy the needs of a variety of users. Software packages must be created for different computers and operating systems. Distribution of software packages must be timely, and services must be provided that range from helping with installation to correcting errors in the code or in the documentation.

Meeting the challenge

In October 1981 EPRI Vice President for Research and Development Richard Balzhiser requested each division to appoint a representative to serve on a committee that would draft recommendations on how to improve all phases of EPRI software development and distribution. The committee's recommendations were approved by senior management in April 1982 and embodied in the document titled EPRI Computer Code Development and Distribution, Principles and Policies, published in September 1983. The Software Product Development Advisory Committee has continued to function as a group to formulate code-related policies and procedures.

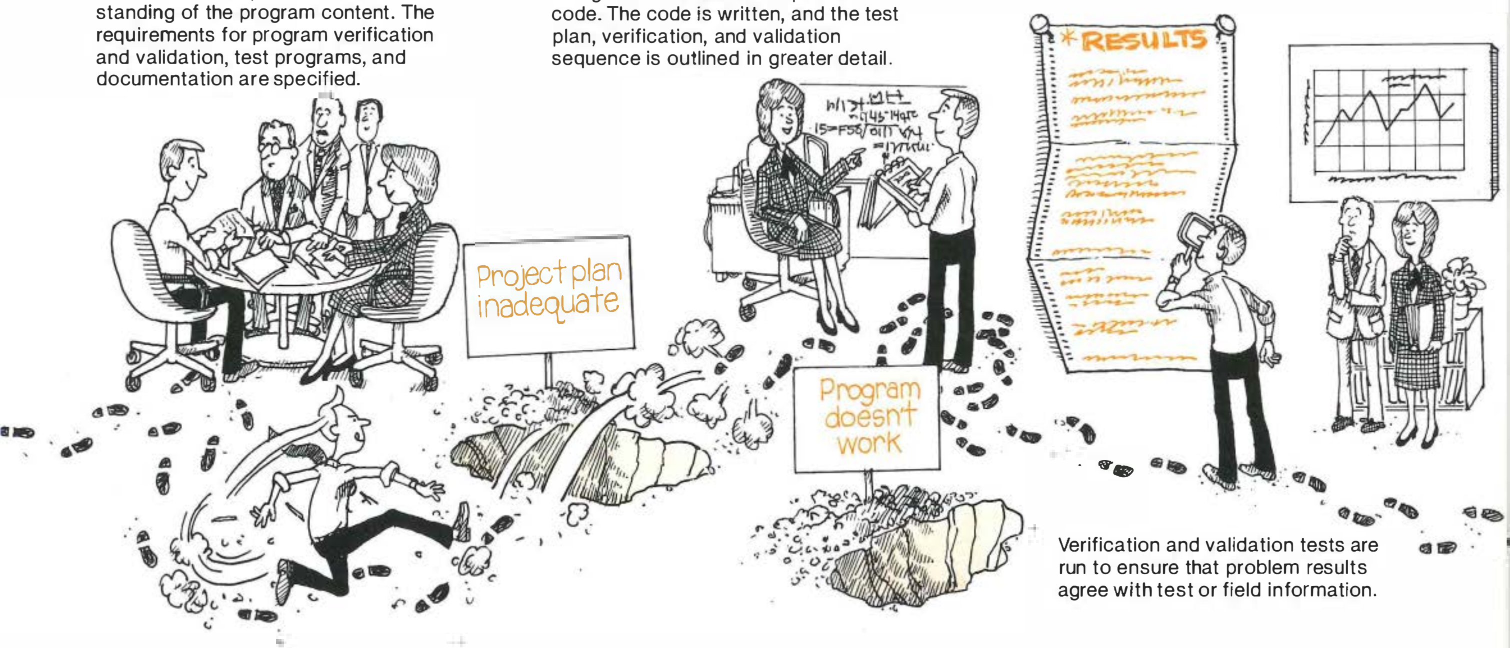
The purpose of the software Principles and Policies is to establish a set of broad guidelines that can improve the overall quality and usability of EPRI's computer codes, while still allowing each division to specify more detailed instructions to meet its particular needs. The emphasis is on promoting a team approach and maintaining orderly procedures to provide vital information that can be used throughout the life of a code, long after the original project manager may have changed assignments or a different contractor may have been selected to make modifications. Most codes have a useful lifetime of a few years. A small percentage, however, may be used for a decade or more, during which time many enhancements will have to be made.

Principles and Policies recognizes two general grades of EPRI codes, which reflect different user needs and development priorities. A research code is generally designed to test a particular R&D concept. Distribution is usually limited to researchers who are aware of the code's

Design and development

The project manager and the contractor's team develop a detailed understanding of the program content. The requirements for program verification and validation, test programs, and documentation are specified.

A mathematical formulation and design features are developed for the code. The code is written, and the test plan, verification, and validation sequence is outlined in greater detail.



Verification and validation tests are run to ensure that problem results agree with test or field information.

specific features and limitations. No testing is required beyond making sure that the code runs.

A production code is designed for general distribution to EPRI member utilities. It must undergo a complete cycle of testing and demonstration, and EPRI is responsible for maintenance and support for a specified time period. Some research codes may be upgraded to production codes, a process that requires additional testing and demonstration. Upgrading also usually involves the addition of user-oriented features, such as easier-to-use input/output formats and provisions for running on different kinds of computers.

Stages of development

Before it can be released for general distribution, a production code must pass through three development stages. In the first, the definition stage, utility needs are identified and incorporated into an overall project strategy. Specific software compatibility requirements are set so a code will be transportable from one kind of computer to another, and necessary user-oriented features are planned. This stage ends when a vendor is selected and the project plan is formalized in a contract.

Next, a code is designed and programmed by the contractor. During this second stage, the code is also verified (checked to make sure the programmed equations are solved correctly) and validated (given a test problem whose results can be compared with data available from experiments, other calculation techniques, or system tests). In the third stage, a code must be demonstrated—evaluated by a group of member utilities using their own data on their own computers.

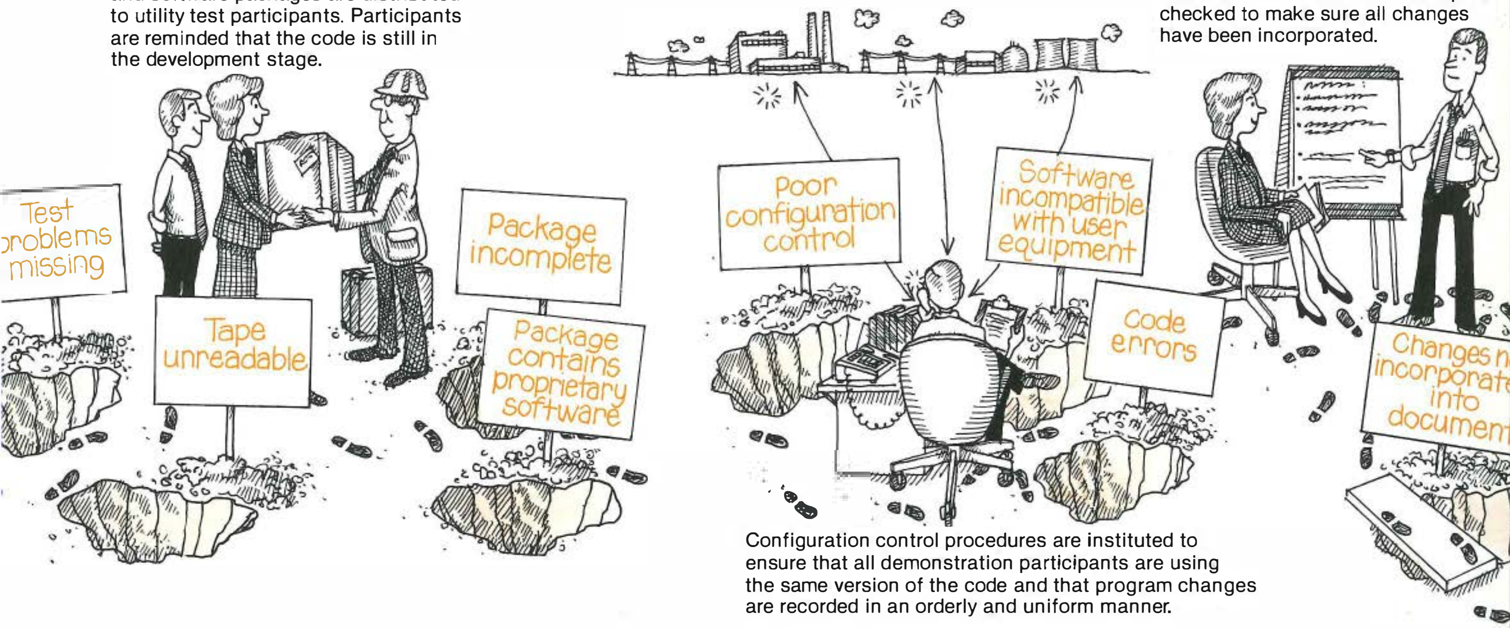
The utilities volunteering to demonstrate a software package make a major contribution to the technical adequacy and usefulness of the final product. They also have a unique opportunity to test newly developed software on practical problems in a realistic utility environment. In addition to checking the technical capabilities, some demonstrations allow codes to be run on various computers and operating systems so that operational problems can be corrected before release. The demonstration phase is critical to the team approach in computer code development because it allows users to interact freely with the developer and the EPRI project manager to ensure a quality product.

Inevitably a utility involved in testing a code before its official release will encounter some difficulties. Steps are then taken to correct the code and to share information about it with the demonstration participants. For some larger codes, user groups have been formed. This aids the EPRI project manager by ensuring that efficient feedback exists among various utilities and between potential users and the developer. Only after the performance of a code has been demonstrated successfully is consideration given to its formal release.

Following its successful demonstration a production code is released through the Electric Power Software Center (EPSC), operated by UCCEL Corp. in Dallas, Texas. The center is responsible for making a final verification test on the code, preparing a complete code package for distribution, processing most types of license agreements, and providing users with installation assistance. Within EPRI itself, the Technical Information Division of the Industry Relations and Information Services (IRIS) group has responsi-

Demonstration

The demonstration plan is prepared, and software packages are distributed to utility test participants. Participants are reminded that the code is still in the development stage.



The demonstration is completed and errors are corrected. The final tape is checked to make sure all changes have been incorporated.

Configuration control procedures are instituted to ensure that all demonstration participants are using the same version of the code and that program changes are recorded in an orderly and uniform manner.

bility for software distribution and overseeing the operation of EPSC.

For users who do not have the necessary computer facilities or personnel to run a particular code, or who do not wish to obtain the code permanently for other reasons, UCCEL also operates the Electric Power Service Bureau (EPSB). Through EPSB, either a user can provide data for a code to be run by the bureau staff on a computer in Dallas, or the code can be run remotely over a time-sharing system. EPSB also provides computer resources for EPRI seminars and workshops. Other service bureaus are operated by Babcock & Wilcox Co. and by Control Data Corp. More than 100 EPRI production codes are now available through EPSC, EPSB, B&W, and Control Data.

Software products around the Institute

The role of software varies greatly among the various divisions of EPRI, as well as between individual projects within each division. A small code may require only a few hundred lines of programming; large codes contain more than a hundred thousand lines. Some codes—like those exercising on-line control of plant operations—are designed to run continuously. Others may be run only occasionally by utility users or contractors but solve some problem of vital importance to the industry. In these cases, the value of just a few applications may far outweigh the cost of developing a code.

Many of the largest codes are those in the Nuclear Power Division. If a nuclear code is to be applied to reactor safety and licensing, the code documentation must be extensively verified and validated against actual plant data. For one code alone—RETRAN, which analyzes possible changes in a reactor's steam supply system—EPRI member utilities have spent millions of dollars on experimental validation, with results incorporated into the code documentation. This process has also helped users understand how to use the code for better plant operation and for providing information when they appear before the Nuclear Regulatory Commission. Generally two versions of a nuclear code are required so it can be run on both International Business Machine (IBM) and Control Data (CDC) computers. Results of test calculations from the two versions of a code must generally agree to five significant figures. (Historically, most utilities have purchased IBM computers but many nuclear codes were originally written for CDC computers.) The division has formed user groups to provide utilities with a forum for discussing plant problems and exchanging information on how best to use a code.

The Electrical Systems Division is another major producer of codes, some of which are very large because of the need to model complex power systems. The ETMSTAB code, for example, must use special techniques to solve the thousands of differential equations involved in analyzing the stability of a large system of interconnected generators and transmission lines. TLOP (transmission line optimization program), which recently became available to utility designers, will search through hundreds of design possibilities, check each to see if it meets the utility-specified criteria, and then identify which design will provide the lowest initial or lifetime cost. To promote greater utility involvement, a users group has been established for the EGEAS (electric generation expansion analysis system) code, which provides several methods for analyzing future capacity expansion

EPRI Software Available Through EPSC

Advanced Power Systems Division

UNIRAM—Power generation system availability assessment model (I)*

Coal Combustion Systems Division

AGDOPP—Air/gas system dynamics of power plants (V)

ASHDAL—Ash disposal cost estimating model (I)

CLGTWR—Cooling tower process model (C, I)

COJOUR—Dynamic coefficients for fluid film journal bearing (I)

DRIVER—Cooling tower chemical equilibrium model (C, I)

FAN—Fan-foundation-soil dynamic response prediction (C)

FANTEST—ASME large fan field test (I)

FEATURE—Finite element analysis tool for utility rotor dynamics evaluation (I)

FGDLIQEQ—FGD liquid equilibrium (PC)

SACTI—Cooling tower plume dispersion model (I)

SLUDGECOST—Cost prediction model for FGD sludge disposal systems (I)

VERA2D—Performance model for evaporative cooling towers (C, I)

Electrical Systems Division

ACPIPE—Powerline-induced ac potential on natural gas pipelines for complex rights-of-way (I)

AESOPS1—Low-frequency eigenvalues basic (I)

AESOPS3—Low-frequency eigenvalues expanded (C, I, P)

AGCSIM1—Area control simulator (I)

BCAB—Cable faults and potentials (I)

BRODI2/BROFLX—Transmission line broken wire (I)

CABLPUL—Maximum pulling lengths for solid dielectric insulated cable (I)

DLFTM—Distribution load forecasting model (I)

DYNEQ1—Dynamic equivalents (I)

DYNEQ3—Extended dynamic equivalents (I)

EGEAS—Electric generation expansion analysis system (I)

ETMSTAB—Transient/midterm stability/PFLOW (I)

FATIGUE—Torsional fatigue strength of large turbine generator shafts (I)

FULSCH—Fuel and generation scheduling (I)

GATL—Grounding analysis of transmission lines (C, I)

GPUC—Generating unit commitment and production costing (I)

HARMFLO—Harmonic power flow program (I)

HVDCHARM—HVDC-AC systems interaction from ac harmonics (I)

MULTI-FLASH—Multiple phase lightning flashover of transmission towers (I)

PADLL—Drilled pier foundation analysis and design (C, I)

POLEDA-80—Single unguyed transmission pole design (C, I)

PRAM/HISRAM—Distribution system reliability and risk analysis model (C, I)

SCALE—Simplified calculation of loss equations (I, P)

SCENDATA—Synthetic utility systems scenario data (I)

SGA—Substation grounding analysis (C, I)

SHORT—Transient temperature of URD cables (I)

SWAP—Statistical weather analysis program (I)

SYREL—Transmission system reliability methods (I, P)

TLOP—Transmission line optimization program (I)

TRADE—Transfer capability objective (I, P)

UDPM—Distribution planning (I)

*Machine compatibility: I = IBM, V = VAX, C = Control Data, PC = IBM Personal Computer, P = PR1ME, G = Generic.

Energy Analysis and Environment Division

ADEPT—Acid deposition decision tree (G)

CMCM—Coal mine cost model (I)

COMMEND—Commercial sector end-use energy demand forecasting model (G)

DETGEN—Decision tree generator model (G, PC)

ELM—End-use load modifier (I)

FAST—Decision framework for ambient air quality standards (G)

HELM—Hourly electric load model (G)

ILWAS—Integrated lake-watershed acidification study (I)

LHS—Local host system (G)

LMSTM—Load management strategy testing model (I)

LSFM—Load shape forecasting model (G)

OVER/UNDER—Cost and benefits of over versus under capacity in electrical power system planning (G)

POWRSYM—Power system production costing model (G)

TCM—Technology choice model (G)

TELPLAN—Integrated utility planning model (G)

UPM—Utility planning model (I)

Energy Management and Utilization Division

COPE—Cogeneration options evaluation (I)

DEUS—Computer evaluation of dual energy use systems (I)

EMPS—EPRI methodology for preferred systems (I)

LOADSIM—Load shape simulation (G)

Nuclear Power Division

ABAQUS-ND—Finite element code for nonlinear dynamic analysis (C)

ARMP—Advanced recycle methodology (C, I)

ATHOS—Thermal-hydraulic analysis of steam generators (C, I)

COMETHE—Predict mechanical and thermal performance of fuel pin (C, I)

COPHIN—Data transformation (C, I)

DATATRAN—Database management/executive system (C, I)

DRIVE—Stress-intensity factors for surface cracks in pipes (G)

ERUDITE—Utility transient fuel behavior data information source (C)

GO-2—System reliability/availability code (C, I)

MANAGE—Multicycle fuel management (C)

MMS—Modular modeling system (C, I)

PSMS—BWR hybrid power shape monitoring system (P)

RETRAN-02—One-dimensional transient thermal-hydraulic analysis (C, I)

SIMULATE-E—Three-dimensional steady-state analysis of LWR power reactor (C, I)

SPDS—Data library (C, I)

SPEAR-BETA—LWR fuel performance estimation code (C, I)

STEALTH-GEN—Explicit finite difference code for solids, structural, and thermal-hydraulic analysis (C, I)

STEALTH-PIPING—Explicit finite difference code for piping flow (C, I)

TORMIS-2—Quantifies effect of tornado-generated missile to nuclear power plant safety (I)

VIPRE1—Thermal-hydraulic analysis code (C, I)

WAMBAM—Fault tree evaluations, probabilistic (C, I)

WHAMSE—Three-dimensional nonlinear structural dynamics (C)

Planning and Evaluation Division

COMPETE—Competitive analysis of electric power generation options over time (I)

CONFIG—Configuration and availability analysis of future power generation units (I)

NEW TOOLS FOR UTILITIES

EPRI codes provide utilities with tools for solving a wide variety of analytic problems. The range and power of these codes is evident from the brief examples that follow.

Advanced Power Systems

UNIRAM (unit reliability and maintainability) evaluates the availability of new or existing power generating units. Utilities use the code to assess availability improvement programs and plant life extension plans before implementing them, as well as to evaluate new plant designs. The code was intended for application to individual generating units, but it is sufficiently general for users to evaluate both plant components and systems. It provides a more quantitative, rigorous approach to the evaluation of benefits than previously available.

Coal Combustion Systems

MMS (modular modeling system), developed jointly with the Nuclear Power Division, simulates the dynamic performance of both fossil fuel and nuclear plants. A user can choose plant components from a library of over 40 modules to assemble a specific plant configuration for analysis.

FEATURE (finite element analysis tool for utility rotor-dynamics evaluation) is an interactive code for analyzing, troubleshooting, and evaluating rotor bearing vibrations in turbine generators, pumps, motors, and fans. A users group of 15 licensed utilities has been formed.

Two related computer models have been developed to simulate cooling tower water system and process chemistry (CLGTWR, DRIVER). So far, approximately 18 licenses of these two codes have been granted.

Electrical Systems

SGA (substation grounding analysis) helps a utility design a substation grounding system that will ensure safe conditions for operating personnel. Specifically, the code can analyze a substation ground grid, given the design of the grounding system and the total current to be injected, or it can analyze the current distribution among various grounded structures to determine possible fault conditions. Previously available approximate methods often called for excess conductors for grounding, which can now be eliminated. Currently 55 utilities have received the SGA code.

Another code, PADDLL, provides the optimal length for a drilled pier foundation of a given diameter in order to sustain designated loads from transmission towers. Savings of 14–20%, compared with costs of previous methods, were projected; the code has been distributed to more than 100 utilities.

Energy Analysis and Environment

TELPLAN (electric utility planning model) is a new code that integrates power system expansion and operation, probabilistic seasonal production costs, and financial simulations into a single computer program. It is unique in its ability to account for the impact of pollution control technologies and regulations. The design of the TELPLAN code emphasizes quick turnaround times, which facilitate the generation of many scenarios needed to evaluate the medium- and long-term planning issues. After two years of using TELPLAN, Consolidated Edison Co. planners concluded that the hundreds of simulations they had run would not have been possible by using traditional analytic methods and that the code was saving the company as much as $200,000 a year in computation costs alone.

Another code, COMMEND, provides utilities with detailed information on the size, growth, and behavior of key commercial market segments.

Energy Management and Utilization

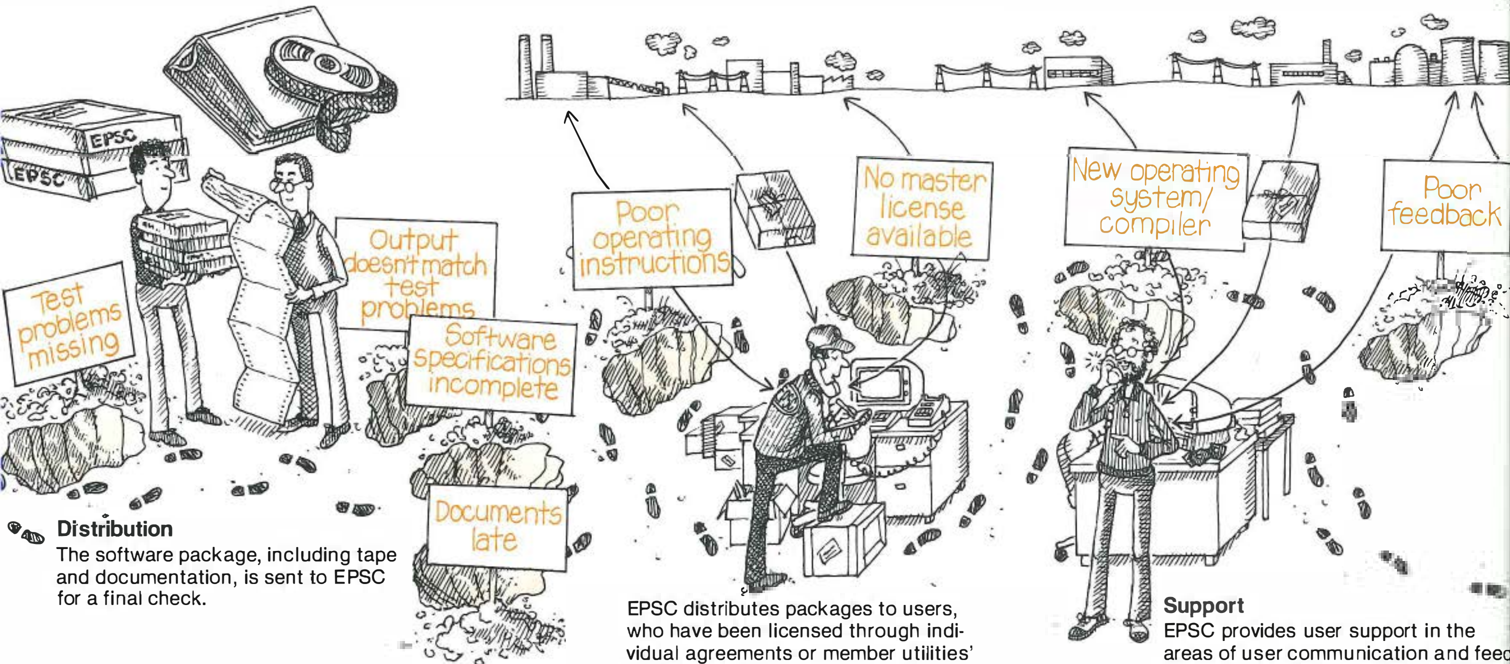
COPE (cogeneration options evaluation model) and DEUS (dual energy use system) provide two ways of determining the likely impact of cogeneration systems. COPE analyzes the financial effects of proposed cogeneration ventures and evaluates their impacts. DEUS gives a site-specific analysis of cogeneration facility design, costing, performance, and economic benefits; it may be used to screen potential cogeneration applications and to select specific equipment and configurations.

Another code, LOADSIM, provides an engineering model of HVAC electric demand in a residential building.

Nuclear Power

The analysis of thermal shock to a reactor pressure vessel during a small-break loss-of-coolant accident (LOCA) provides an example of how computer codes contribute to the resolution of a major industry problem. Extensive data on radiated pressure vessel material properties had been collected for many years, but systems analyses were needed to determine whether excessive stresses would occur. To address this problem, the RETRAN reactor transient code was used to determine the flows, pressures, and temperatures that result from a small-break LOCA. The output of this analysis was then fed into three other codes to calculate three-dimensional flow patterns and relevant stresses. The results of this project helped several utilities relieve concerns with reactor vessel materials.

The Nuclear Power Division is currently coupling most of its large production codes into the reactor analysis support package (RASP). RASP builds on existing EPRI best-estimate methodology to extend the range of applications in logical steps. □



Distribution
The software package, including tape and documentation, is sent to EPSC for a final check.

EPSC distributes packages to users, who have been licensed through individual agreements or member utilities' master licenses.

Support
EPSC provides user support in the areas of user communication and feedback, distribution records, installation assistance, and problem/error logging

plans. This users group, which had more than 100 members by mid 1984, provides a forum for communication among the 64 organizations that have so far received copies of the EGEAS code.

Codes in the Energy Analysis and Environment Division range widely in their applications, from end-use forecasting and corporate planning to risk-benefit decision making, engineering simulation, and models of environmental phenomena. Policy assessment tools, like ADEPT (acid deposition decision tree model), can bring a measure of objectivity to national deliberations. Models of physical phenomena, like PMV&D (for plumes) and ILWAS (for lake acidification), represent important tools for utilities to use in licensing and policy formation.

Coal Combustion Systems Division codes generally concentrate on helping utilities improve day-to-day plant operations. Some of these codes, like MMS (modular modeling system), tell an operator how a plant will respond if he changes certain conditions and variables, like shutting down a pump. FEATURE (finite element analysis tool for utility rotor-dynamics evaluation) can troubleshoot vibration problems in rotating turbines, fans, and pumps. Other codes help in planning new plants by allowing a utility to evaluate various design options for, say, reducing fuel costs.

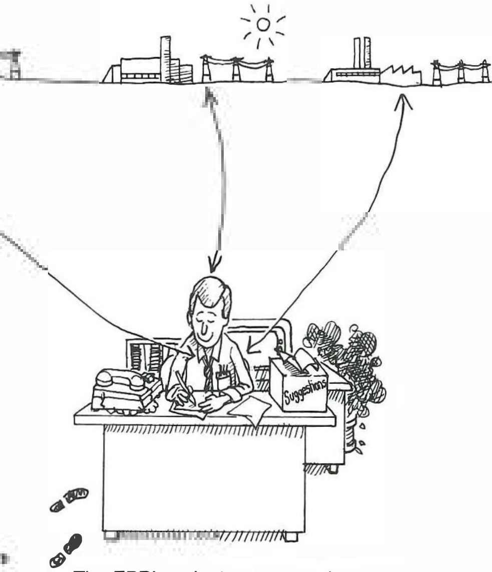
Advanced Power Systems Division codes also stress plant performance and reliability, but in the context of longer-range development. Such codes are particularly useful during cost estimation and preliminary engineering design of new plants. One production-grade code is now available, UNIRAM (unit reliability and maintainability), which can be used to evaluate the reliability and availability of different kinds of power plants.

Codes developed by the Energy Management and Utilization Division can help utilities select the preferred strategies for implementing new end-use devices. Using LOADSIM (load shape simulation), for example, a planner can simulate a large number of load management or conservation strategies and predict the effects of each on customer comfort and utility load shape. The division's cogeneration codes—DEUS (dual energy use system) and COPE (cogeneration options evaluation model)—can help both a utility and its generating partner to design a cogeneration facility and to evaluate the impact on both parties.

The Planning and Evaluation Division offers two codes of production grade. COMPETE (competitive analysis of electric power generation options), which performs an economic analysis of new generator options, and CONFIG (configuration and availability analysis of future power generation units), which calculates availability models for individual generating units.

Remaining issues

Until about five years ago the rights to use EPRI software were provided relatively freely to all utilities, whether they were EPRI members or not. Now, to recover development costs from all software users, more-formal procedures and an equitable fee schedule have been instituted by Patents and Licensing, Office of Corporate Affairs. EPRI members in good standing can enter into a master licensing agreement that enables them to obtain all production codes not containing proprietary information. Special license arrangements and fees are used for other organizations and for utilities that are not EPRI members.



The EPRI project manager also participates by obtaining user feedback, correcting errors, and passing along suggestions on program enhancements.

Because the majority of the released codes are relatively new, EPRI experience with the cost of supporting the use of software is limited. Hence, the cost of maintaining some major codes has not been determined. A related consideration being addressed is how to accommodate the computer hardware and operating system changes resulting from new computer purchases by member utilities. The increasing use of personal computers and workstations, for example, suggests that a significant number of EPRI codes will eventually be designed for smaller computers. One code being distributed for use on a personal computer is FGDLIQEQ, a Coal Combustion Systems Division code that gives chemical properties of a flue gas desulfurization system from analysis of liquid samples obtained from various points in the system. The Energy Analysis and Environment Division has one code available for personal computers, DETGEN (decision tree generator model); and one mainframe code, ADEPT (acid deposition decision tree model), is now being adapted for use with personal computers. The Electrical Systems Division has sponsored development of a minicomputer-based workstation software package designed for structural analysis of transmission towers. And the Energy Management and Utilization Division's LOADSIM is undergoing final tests for use in personal computers.

Although most of the earlier problems with code development and distribution have been resolved, the rapidly expanding diversity and scale of EPRI software continues to require new management initiatives. Current attention is being focused on technology transfer in its broadest sense—maximizing the usefulness of software to member utilities. With most administrative problems associated with software distribution out of the way, the questions that now arise concerning EPRI software focus on the technical content of various codes.

This trend reflects the growing use of EPRI codes by utilities, so new ways of obtaining user feedback are being tested. The Electrical Systems Division, for example, is sending a survey form to each new code user, asking for comments on the organization's experience with the code. Similarly, the Member Services regional managers are working with member utilities to obtain feedback about their experiences with EPRI codes.

A number of code commercialization concepts are being considered—for example, granting a private vendor a nonexclusive license to market an EPRI code in return for providing maintenance and enhancement. "We're just beginning to struggle with the issue," says Milton Klein, vice president for the Office of Special Projects, which handles commercialization. The problem is how to find ways to have private companies share some of the expense of supporting a code, while EPRI still maintains quality control.

The primary responsibility for technology transfer of software still lies with the project managers in charge of individual code development. Several technical divisions, however, have recently appointed technology transfer administrators, who will help utilities recognize the growing importance and diversity of EPRI software available to them.

"I believe we've made good progress in coping with the rapid growth of software," affirms Esselman. "The new policies adopted by EPRI management and the new activities inaugurated by each of the divisions have done much to ensure the uniform quality of code development and ease of distribution. In the future we will be addressing other issues that must be resolved to be certain that EPRI software continues to meet the needs of member utilities." ■

This article was written by John Douglas, science writer. Background information was provided by Walter Esselman and Kathy Kaufman, Engineering Assessment and Analysis.

Heber: Key to Moderate-Temperature Geothermal Reserves

Binary-cycle technology offers a way to unlock moderate-temperature geothermal brines, effectively doubling the geothermal resources available for development through the year 2000. EPRI's 45-MW Heber demonstration plant in California's Imperial Valley will prove the technology for large-scale power production.

Getting energy out of the earth is never easy. Sometimes, nature cooperates: A few geothermal reservoirs vent steam ready-made to turn the turbines of power plants, and many more reservoirs yield brines so hot that when pumped to the surface and depressurized they instantly flash into steam. But more often, geothermal fields produce moderate-temperature brines of 150–210°C (300–410°F), not nearly hot enough for efficient direct power generation. Now there is a new power plant in the Imperial Valley of California that will demonstrate a commercial-scale technology for coaxing electricity out of these reluctant brines.

The technology is the binary cycle, and the plant is the 45-MW Heber binary-cycle geothermal demonstration, scheduled to begin operation early this year. Sponsored by EPRI, DOE, San Diego Gas & Electric Co. (SDG&E), Southern California Edison Co., the Imperial Irrigation District, the California Department of Water Resources, and the state of California, the $122 million project is expected to demonstrate by 1988 that the binary cycle is technically and economically ready to generate large-scale power from moderate-temperature geothermal brines.

The secret for extracting electricity from moderate-temperature brines lies in Heber's working fluid. Unlike direct-flash geothermal technology, which uses steam flashed from reservoir brine as its working fluid, the binary-cycle method uses a hydrocarbon fluid that boils at a lower temperature than water. This means that less energy is required to produce the vapor that spins the plant's turbines. Because the binary-cycle system yields the same amount of electricity as the direct-flash system with only two-thirds the amount of geothermal brine, fuel costs are lower, making it possible to develop moderate-temperature resources that would otherwise be uneconomic. (The Heber binary-cycle plant is not to be confused with a 47-MW Heber flash plant being constructed about a mile away by Heber Geothermal Co.)

Because moderate-temperature brines are at least 50 times more common than dry steam and 4 times more common than high-temperature brines, the Heber binary-cycle project is expected to open up new geothermal resources for developers. "By making these brines economically recoverable, binary-cycle systems could double this country's available geothermal resources," says Vasel Roberts, manager of the Geothermal Power Systems Program at EPRI. He estimates that moderate-temperature hydrothermal resources represent a potential generating capacity of 100,000 MW for at least 30 years, possibly 10 times that capacity in the long run.

EPRI has been working toward this goal since the Institute's first geothermal workshop in 1974. The site in the Imperial Valley was selected from among 18 candidates in the western United States because it had typical hydrothermal temperatures and pressures and because extensive drilling and resource assessment were already available in the Heber geothermal field. Under a purchase agreement with Chevron Geothermal Co. of California and Union Oil Co. of California, hot brine will be pumped up from 13 different wells and piped to the plant at 182°C (360°F). There the brine will be sent through a series of tube-and-shell heat exchangers where the earth's energy will be transferred to the hydrocarbon working fluid. The hydrocarbon fluid will boil into a 152°C (305°F) vapor that will spin the plant's turbine. The power generated will be shared by several of the project participants, and after a three-year test and demonstration period, the plant is scheduled to go into commercial service, operated by SDG&E to produce power for the participants.

From small to large

Small-scale binary-cycle systems ranging from a few hundred kilowatts to a few megawatts in capacity have been used for many years in industrial applications, such as waste-heat recovery. The binary cycle has even been used experimentally in a few small power plants, including a 10-MW plant built by Magma Power Co. in 1979 in the Imperial Valley. But as the binary cycle's first large-scale test, 45-MW Heber has to prove itself before utilities and geothermal developers will buy the technology.

To help reduce the cost and performance uncertainties that would-be developers worry about, Heber is equipped with an extensive data acquisition system that will measure overall plant performance as well as the performance of major subsystems and equipment. Testing will start when brine delivery begins in early 1985. By 1986, after a year of testing, brine delivery will be brought up to 100%, and the plant will swing into a two-year demonstration period, including further tests. Data collection, evaluation, and documentation will occur on a continuing basis from the beginning to the end of the project, and the results will be available to interested parties.

Utilities will be closely watching Heber during this test and demonstration period. They want to know, for example, what it is like to use hydrocarbon working fluid on a large scale. Plain old water has always been the working fluid for the utility industry's coal, oil, nuclear, and hydroelectric plants, and uncomplicated air is the working fluid in gas turbine plants. But Heber's flammable 90% isobutane–10% isopentane mix demands different designs and operation and maintenance procedures. "These substances are already widely and safely used in large petrochemical and refinery plants," explains John Bigger, EPRI's project manager for Heber, "but the Heber turbine, rated for a gross output of 70 MW, is three times larger than the largest hydrocarbon turbines built to date for any other purpose. Over eight million pounds of working fluid move through the plant in an hour—that's a lot of hydrocarbon fluid to have rolling around." Heber will demonstrate the safety of the binary cycle and give engineers the opportunity to develop O&M guidelines that will ensure that safety.

Another unknown that Heber is expected to clarify is the effect a large power plant has on the production capabilities of a moderate-size geothermal reservoir. Brine in a binary-cycle system is circulated through a closed loop, and the spent brine is returned to the reservoir unchanged except for lowered temperature. Once back in the natural reservoir, the brine will eventually be reheated and ultimately reused. Reinjection of spent brine at Magma's small 10-MW binary-cycle plant has had no apparent effects on reservoir performance or capability, but Heber is much larger than previous facilities, taking in about 945 kg/s (2083 lb/s) of brine. Scientists and engineers have developed models that predict the effects of the plant on the reservoir, but, acknowledges Bigger, "we can't model a geothermal reservoir with absolute accuracy just yet." Engineers will study Heber to learn how reservoir and power plant interact and how to utilize the geothermal resource for maximum efficiency.

To ensure that the closed brine and hydrocarbon systems are kept separate, the Heber plant includes a full complement of leak-detection sensors. Sensors on the brine side of the heat exchangers, for example, will detect any hydrocarbon fluid that has found its way into the brine, so the plant can be repaired to prevent loss of hydrocarbon inventory. Similarly, sensors on the hydrocarbon side will alert operators to any brine leaks.

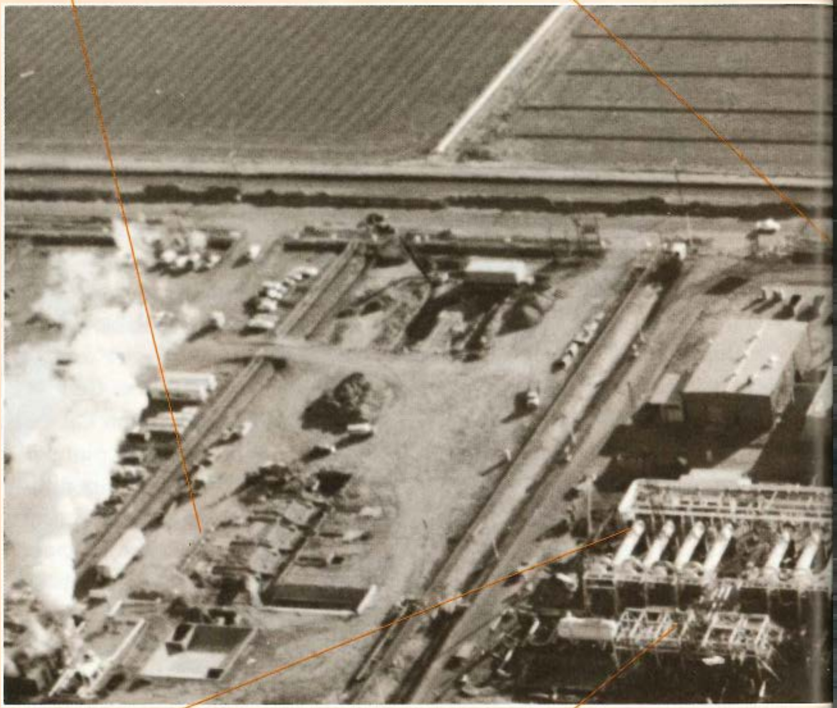
Corrosive brew

Yet another area of effort at the Heber binary-cycle project is corrosion control. Because geothermal brines brew at high temperatures and pressures underground, most brines have significant mineral content. Some brines are so saturated with corrosive, erosive, and scaling materials that when pressures and temperatures drop suddenly in the process of heat extraction, the dissolved minerals precipitate out, causing scaling. This can hurt performance and even damage such equipment as turbines in

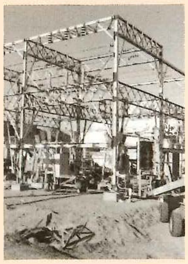
The Inside Story on the Heber Binary-Cycle Demonstration Plant

Out on the production island, a small area at the surface from which wells are directionally drilled to tap different parts of the reservoir, 182°C (360°F) geothermal brine is pumped up from four production zones ranging from 2000 to 10,000 ft (610–3050 m) deep. Each of 13 slant-drilled wells delivers 76 kg/s (600,000 lb/h) of brine at a pressure of 1.72 MPa (250 psia) to the plant's heat exchangers.

Heber's computerized central control system has state-of-the-art monitors, controls, and data acquisition equipment to help evaluate plant performance, operability, and reliability.



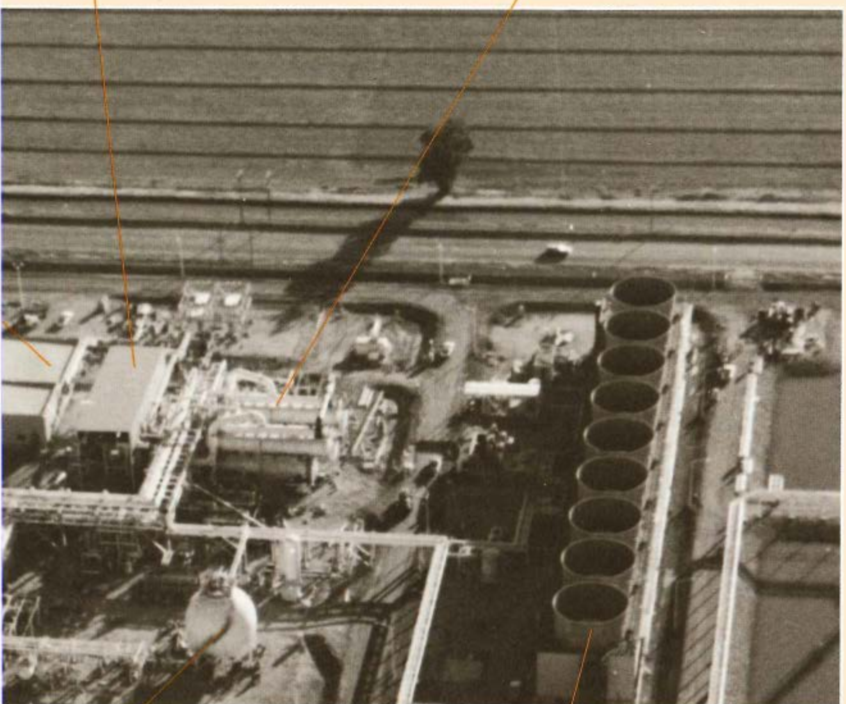
Hot geothermal brine flows through two parallel brine-hydrocarbon heat exchanger trains of four units each. There the hydrocarbon fluid is heated from a 38°C (101°F) liquid to a 152°C (305°F) supercritical vapor.



Out in the switchyard, the plant's electrical output is transformed from 13,800 Vac to 34,500 Vac and connected to the Imperial Irrigation District's distribution system for delivery to customers.

Inside Heber's special hydrocarbon turbine, the superheated hydrocarbon vapor spins the turbine that drives the 70-MW electric generator.

In the condensers, the hydrocarbon vapor is condensed to a liquid and cooled, then pressurized in the hydrocarbon circulation pumps and sent back to the heat exchangers for reheating.



The 44-ft-diam (13.4-m) carbon steel hydrocarbon storage sphere can hold the entire hydrocarbon inventory when the plant is not operating. When the plant is running, the sphere is about 10% full.

The nine-cell cooling tower reduces the temperature of the cooling water, which circulates in the two condensers at 140,000 gal/min (8830 kg/s), from 36 to 24°C (96 to 76°F).

steam or direct-flash plants and heat exchangers in binary-cycle plants. To avoid this, steam is purified before reaching the turbines of dry steam or direct-flash systems. At Heber the brine side of the binary system will be pressurized to 1.7 MPa (250 psia) to reduce mineral precipitation, as well as to keep the brine from flashing into steam.

Even so, Heber will have so much brine coursing through its heat exchangers that it will be shut down periodically for preventive maintenance. A good part of the Heber project involves studying how long corrosion, erosion, and scaling problems take to develop, under what circumstances they develop, and how they can be resolved. Material test stations located throughout the plant will help detect problems, and engineers will experiment with various materials and techniques for preventing and removing mineral deposits.

When results come in

The Heber binary project will have completed its test and demonstration program by early 1988. Data from the project should reassure utilities and other prospective developers that large-scale binary-cycle technology is ready to open up the moderate-temperature reserves of the western states. Utilities may not be the only organizations to develop moderate-temperature geothermal plants: third-party developers are also interested. Under PURPA regulations, utilities are required to buy any electricity that independent developers are willing to sell, and under other federal and state regulations (some soon to expire), developers also receive tax credits for developing renewable resources. A number of third-party developers are already making the most of this situation to build geothermal, wind, and solar plants.

John Cummings, director of EPRI's Renewable Resources Systems Department, feels certain that even when the tax credits run out geothermal will be here to stay: "How fast binary-cycle geothermal plants move depends on the alternatives. Coal, oil, and gas prices are bound to go up, but the cost of the geothermal resource is not expected to rise as fast." In the long run, it seems, geothermal cannot help but prevail. Full-scale binary-cycle geothermal plants will probably be built in Heber-size units of about 50 MW. Plants much larger than that are unlikely because geothermal fluids would lose too much heat if they had to be pumped long distances over geothermal fields to a central plant.

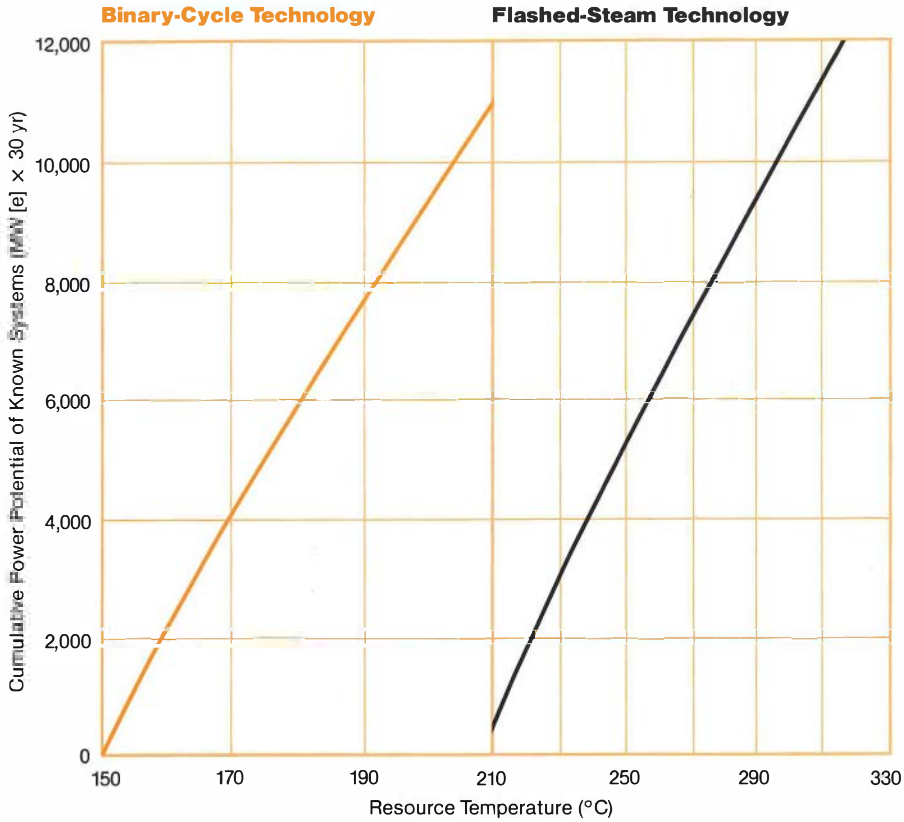
For more cautious developers who may not want to invest in a large-scale geothermal plant right away, EPRI and others in the geothermal industry are developing small wellhead power plants of about 3–8 MW capacity. A standardized, shop-fabricated plant could be quickly installed at an individual well to convert thermal energy into electricity right at the wellhead. Such plants would allow developers to conduct a longer-term test of the field and earn some revenue at the same time. "As the field proves its worth, more wellhead plants can be added," explains Evan Hughes, EPRI project manager. "Eventually, all the wells could be connected to a larger central plant of 50 MW or so, and the original wellhead units disconnected and moved to other test fields." Wellhead plants can also permit utilities to pace geothermal development to slow or uncertain load growth.

EPRI's first wellhead system was a 1.6-MW rotary separator–turbine unit originally designed as a prototype for improved direct-flash technology. Now EPRI plans to develop a binary-cycle wellhead system that uses Heber technology but on a much smaller scale. Binary wellhead plants in moderate-temperature fields might be expected to have capacities of 3–8 MW.

Heber's contribution

Getting energy out of the earth is not easy, but the Heber binary-cycle project is doing its part. "Heber will demonstrate that a binary-cycle geothermal system works on a significant scale," con-

High-temperature geothermal resources (those greater than 210°C) have been readily recoverable for years by flashed-steam technology, but the number of such known resources is relatively small. Successful development of binary-cycle technology, which can tap energy from moderate-temperature wells (150–210°C), will make about four times as many resource systems available for electricity generation, almost doubling the power generation potential of identified geothermal resources.



Heber Binary-Cycle Project: Vital Statistics

Key Project Dates	
December 1980	Project participation agreements signed
May 1983	Approval by California PUC
June 1983	Site construction begun
April 1985	Turbine roll
April 1988	Completion of demonstration
Geothermal Brine Characteristics	
Production depth	2000–10,000 ft (610–3050 m)
Supply temperature	360°F (182°C)
Supply pressure	250 psia (1.72 MPa)
Flow rate	7.6×10^6 lb/h (960 kg/s)
Reinjection temperature	162°F (72°C)
Reinjection pressure	320–595 psia (2.2–4.1 MPa)
Total dissolved solids	14,500 ppm
Power Plant Parameters	
Capacity (net)	46.6 MW (e)
Heat rate (net)	29,620 Btu/kWh
Resource utilization	6.8 Wh/lb brine (3.1 Wh/kg brine)
Hydrocarbon circulation	8.4×10^6 lb/h (1060 kg/s)
Cooling water circulation	140,000 gal/min (8830 kg/s)

cludes John Bigger. "It will identify the performance characteristics of a specific reservoir and demonstrate the accuracy of our reservoir and plant models. Heber will also act as a kind of pathfinder for regulatory, legal, and institutional aspects of binary-cycle geothermal development that may not have been thought of yet. The project will give the financial community a basis to estimate the risks and benefits associated with geothermal investments. And Heber will show that binary-cycle technology is an environmentally, socially, and economically acceptable way to generate electricity." With results like these, EPRI's binary-cycle geothermal program can crack reserves wide open that once weren't worth tapping. ■

WHAT THE EARTH HOLDS

Simmering under the earth's surface are many quadrillion (10^{15}) Btu of geothermal energy. In the United States alone, there are more than 220 quadrillion Btu of known heat deposits within reach of current drilling technology of sufficient quality to produce electricity, most of them in the western states. Geothermal energy is reliable and apparently inexhaustible, but developers have to get it out of the ground first.

Most geothermal energy is destined to remain underground for a long time to come because the drilling and extraction techniques for bringing it to the surface are too costly for commercial ventures. Developers are able to extricate the energy from hydrothermal systems, where hot water or (more infrequently) steam fills the pore spaces in a reservoir of sand or rock. But these techniques are not suitable for geopressured systems, which contain hot water and natural gas trapped securely at high pressure between layers of impermeable shale, or petrothermal systems, which are beds of magma and hot, dry rock, warmed by volcanic activity or the movement of the earth's crust.

That leaves only hydrothermal reservoirs within the reach of today's developers, yet even that one small part of the geothermal resource has kept them busy. Today there are some 3825 MW of installed geothermal capacity worldwide, according to Ronald DiPippo, engineering professor with both Southeastern Massachusetts and Brown universities and long-time observer of geothermal trends. In the United States alone there is a total of 1509 MW of geothermal generating capacity. The first U.S. plant went into operation in 1960, an 11-MW unit at The Geysers in northern California. The Geysers has since expanded to become the largest dry steam development in the world, with a capacity of more than 1400 MW. In southern California's Imperial Valley, three 10-MW hydrothermal plants—two direct-flash and one binary-cycle—have been operating since 1980. In Mammoth, two 3.5-MW binary-cycle units are being constructed. Numerous other small projects—some binary-cycle, some direct-flash—are being planned and built elsewhere in California, Nevada, Oregon, Utah, and Hawaii. All told, there are about 55 MW on-line in the United States outside of The Geysers, and perhaps 444 MW could be operational by the end of the decade.

Geothermal development is also proliferating overseas, according to DiPippo. In the Philippines there are now 781 MW of capacity from 19 units at four fields. Some 2266 MW are planned by 1990. Geothermal energy now accounts for 20% of the total electricity generation in that country. When two 110-MW units are completed at Cerro Prieto III this year, Mexico will have 645 MW of geothermal capacity, and further development should bring the total to 1085 MW by the early 1990s. In Japan there are eight plants in operation—one dry steam and seven direct-flash—for a total of 215 MW, and another 108 MW are in the planning stages. Other countries with geothermal plants planned, under construction, or up and running include China, El Salvador, Iceland, Indonesia, Italy, Kenya, New Zealand, Nicaragua, the Soviet Union, and Turkey. Even though geopressured and petrothermal reserves remain locked inside the earth for now, there are enough geothermal resources to keep developers busy. □

Further reading

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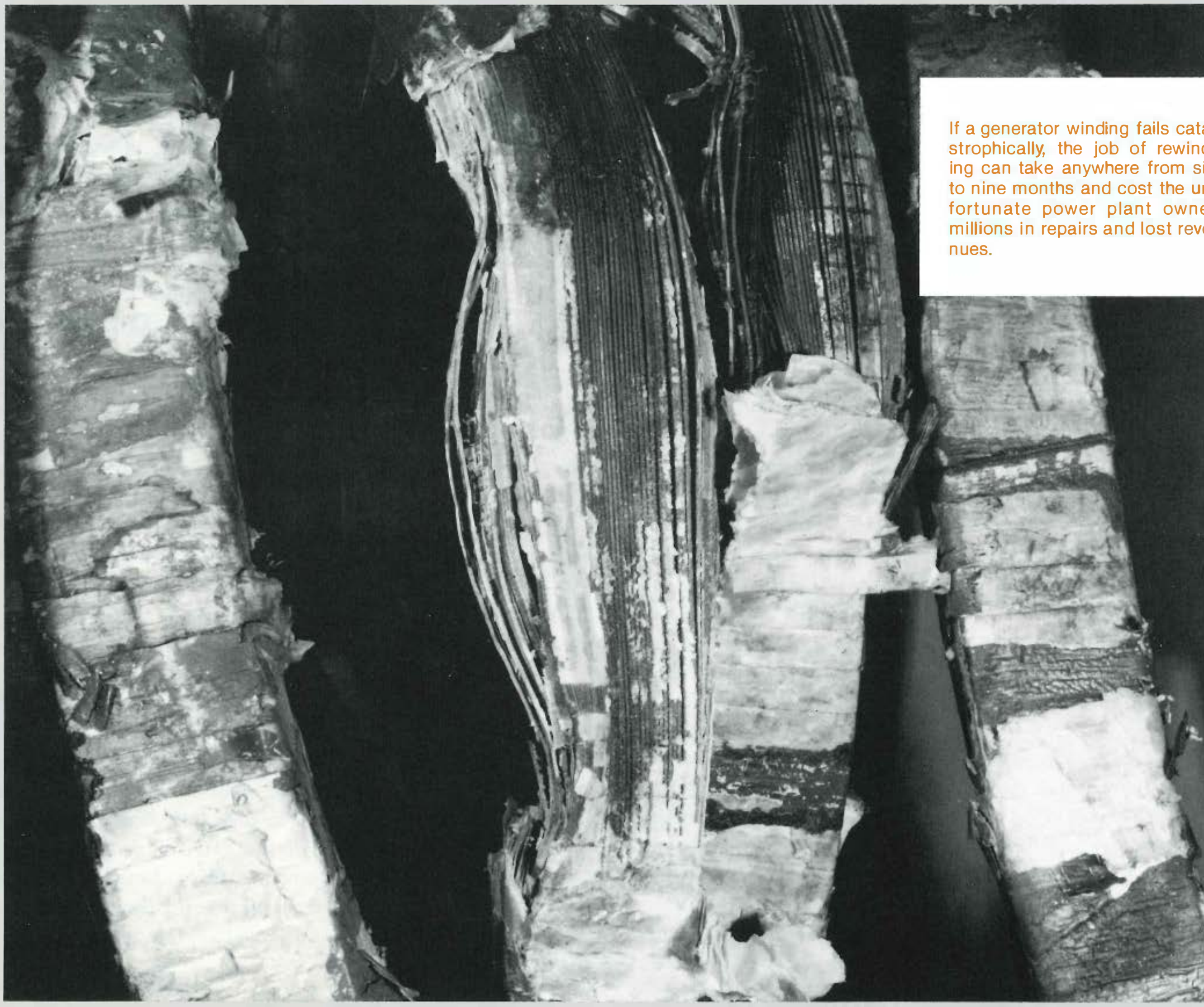
This article was written by Nadine Lihach. Technical background information was provided by John Bigger, John Cummings, Evan Hughes, and Vasel Roberts, Advanced Power Systems Division.

Advance Notice of Generator Failure



If a generator winding fails catastrophically, the job of rewinding can take anywhere from six to nine months and cost the unfortunate power plant owner millions in repairs and lost revenues.

A monitor that picks up radio-frequency signals caused by abnormal arcing within a deteriorating generator gives operators extra time to avert equipment failures.

Utilities are eavesdropping on their electric generators with a piece of EPRI-developed equipment, and what they've been hearing may save them millions of dollars. The equipment is a radio-frequency monitor developed under contract with Westinghouse Electric Corp. The device picks up radio signals caused by abnormal arcing within a deteriorating generator and warns plant operators that a failure may be coming. By alerting operators well in advance, the monitor can save a utility as much as seven months out of service for major generator repair. About 50 Westinghouse monitors are now being used by utilities, and other utilities are adapting the technique for their own purposes.

Early warning

Advance notice of generator failure is especially important in the utility industry, where the cost of power to replace the output of a downed unit ranges from \$250,000 to \$1,000,000 a day. Utilities have been using a variety of devices to protect and monitor generators, but with mixed success. Most utilities monitor electric current at the line end and the neutral end of each of the three phase windings in the generator; a current imbalance instantly trips the generator out of service. Utilities also use gas-condition monitors that measure particulates in the generator's cooling gas; increasing numbers of particulates signal overheating.

The warning that these devices provide is welcome, but it sometimes comes only after some damage has been done to the generators. The radio-frequency monitor can alert operators to a deteriorating condition inside the generator much sooner. Arcing between the ends of broken copper conductor strands or from imperfections in conductor insulation produces radio-frequency signals that emanate from the source of arcing in much the same way as a radio signal emanates from an antenna. (In fact, in the early days of radio, transmitters were essentially small generators that produced arcs; the arcing, tuned by coils and capacitors, was the radio's signal.) EPRI research, begun in 1977, showed that these radio-frequency signals could be detected in the generator neutral lead.

Success from the start

EPRI and Westinghouse decided to assemble a prototype monitor to see how well the technique worked in power plants. The device did not keep them waiting long before it proved its worth. While developmental testing was being conducted in 1979 at Texas Utilities Generating Co.'s Martin Lake station, abnormal arcing was discovered in two generators. The generators were taken out of service, and cracked and broken copper conductors were the problem. Savings in repair costs were estimated at \$500,000.

Testing continued, revealing arcing from broken conductors as well as from bearings and seals in several generators at other plants. By 1980 Westinghouse and EPRI were satisfied with the prototype. "Westinghouse assembled a complete commercial package that included the basic monitor, data recording equipment to keep track of trends, and alarm circuitry to alert operators to emergencies," says Gordon Shugars, who managed the original project in EPRI's Nuclear Power Division. By monitoring signals over a period of time, a utility can spot a deterioration trend and either take the unit out of service for immediate attention or plan on doing so at the next scheduled outage.

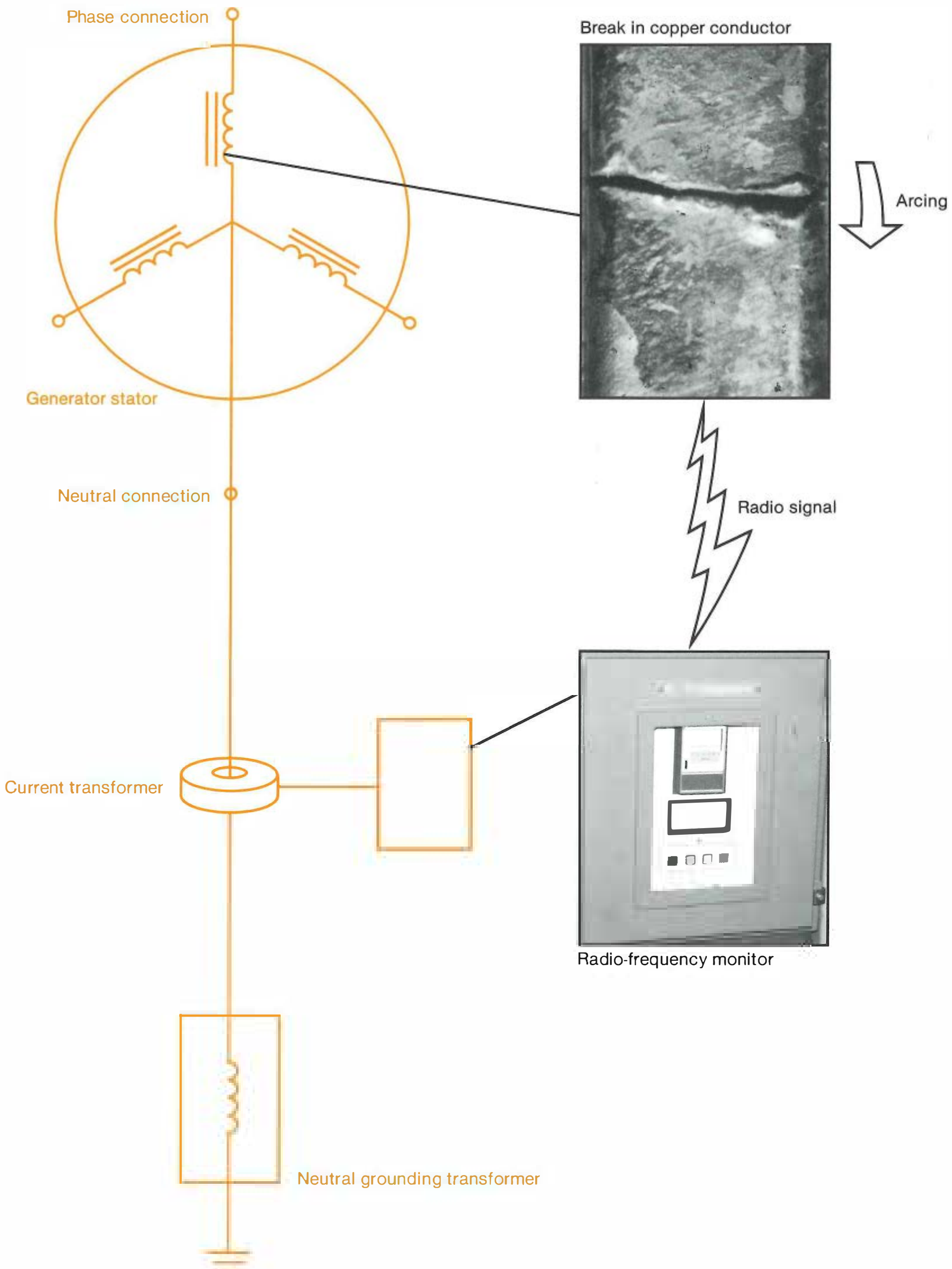
Since the monitor was first introduced, some 50 systems have been sold to utilities anxious to forestall generator failures. Texas Utilities alone has ordered systems for full-time monitoring at seven generating units; the cost of the monitors will be more than recovered if the warning system prevents just a single major generator failure. Another satisfied user is Maine Yankee Atomic Power Co. The utility uses the Westinghouse monitor to check continuously on the generator at its Maine Yankee plant in Wiscasset. Data from the monitor are fed directly and continuously into the plant's central computer, averaged, printed out daily, and reviewed by Roger Jutras, Maine Yankee's lead electrical engineer. In September the radio-frequency monitor spotted what looked like trouble in the generator. Inspection during a subsequent scheduled outage revealed a problem, which was fixed, although it was not clear that that was the source of the arcing. Nevertheless, Maine Yankee appreciated the advance warning. The monitor adds another degree of security to the continued reliable operation of the generator.

The monitor was recognized as one of the 100 most significant technologic advances of 1980 when *Industrial Research & Development* magazine awarded it the IR-100 Award in 1981, but James Edmonds, project manager in EPRI's Electrical Systems Division, points out that the Institute's radio-frequency technique has even more potential. For example, the Westinghouse monitor is tuned to pick up signals at 1000 kHz, a common arcing frequency. Yet an ailing generator may emit signals at other frequencies as well. EPRI and Westinghouse are now modifying the monitor to pick up a broader range of frequencies, according to Edmonds.

The monitor may also be used to pick up signals from other plant equipment, many of which emit identifiable radio frequencies. By using spectrographic analysis devices to "fingerprint" the signals of individual pieces of equipment, experienced operators can more closely pinpoint the source of a problem before a unit is taken down for repairs, saving utilities even more time and money.

Frequency fiddling

Some utilities have been so fascinated by the monitor's seemingly limitless possibilities that they are doing some tinkering on their own to develop plant-specific systems based on EPRI's original technique. Union Electric Co., for example, was interested in trying out the monitor on a few of its generators, but a local radio station used a 1010-kHz frequency, When one of the many copper conductors that makes up a generator winding snaps from fatigue, a small electrical arc bridges the break. In time, more conductors may break, and the arcing increases until the generator fails. Fortunately, any arcing produces identifiable radio frequencies, and the EPRI-developed monitor can pick up these SOS frequencies and warn operators that a failure may be coming.



and the utility felt that was too close to the monitor's 1000-kHz band for comfort. So, under the direction of the late William Henne of Union Electric's power operations department, the utility designed its own radio-frequency monitor to pick up frequencies from 150 kHz to 25 MHz. With assistance from Hewlett-Packard Co., Union Electric built and installed this monitor in early 1983 at its Rush Island plant; the company later installed another system at its Labadie plant.

Union Electric is trying to correlate the various frequencies that appear on the monitor's spectrum analyzer with specific problems at the plants. David DeSpain, a Union Electric special-projects engineer, says that the monitor has identified at least three problems so far, none of them the generator arcing that the original EPRI monitor was designed to detect. In one case the monitor detected noise that turned out to be a loose exciter connection; in two other cases, the rotor on a generator had lost its ground.

Up in Canada, Ontario Hydro is using a radio-frequency monitor to detect corona discharges in motors instead of arcing in generators. Corona discharges are the tiny sparks that occur when highly stressed insulation deteriorates. These discharges are smaller and harder to detect than arcing, but they can also lead to machine failure. Using some of the EPRI techniques, Ontario Hydro developed a broad-band monitor that picks up frequencies in the 1–30-MHz range. The monitor's data are periodically recorded, according to Mo Kurtz, senior dielectrics engineer with Ontario Hydro. If a suspicious new trend is spotted, Ontario Hydro performs spectrum analysis to try to pinpoint the trouble.

In an effort similar to EPRI's, American Electric Power Co., Inc. (AEP), has developed an on-line radio-frequency monitor that is now being used to observe generator voltages on nine units and brush arcing on two units. If trouble is detected, AEP brings in a van that it has equipped with additional sophisticated detection equipment to isolate the problem. AEP offers this detection service to other utilities as well. "To date," reports AEP staff engineer James Timperley, "we haven't found any steam turbine generator problems, but we have identified problems in transformers, exciters, cables, and other equipment." Frequency fingerprints seem to be the key.

The next version

Westinghouse and EPRI are continuing to develop the radio-frequency monitor to expand its capabilities. A new prototype that offers broad-band frequency detection and automated spectrographic analysis is now being tested at West Penn Power Co.'s Harrison station in Haywood, West Virginia, and development should be completed by mid 1985. The monitor will be commercially available to utilities shortly thereafter. With trouble-detection devices like these around the plant, utilities can breathe a little easier. ■

This article was written by Nadine Lihach. Technical background information was provided by James Edmonds, Electrical Systems Division, and Gordon Shugars, Nuclear Power Division.

OTA: Technical Guidance for Congressional Decisions

The Office of Technology Assessment (OTA), situated just six blocks from Capitol Hill, helps guide Congress on scientific issues by performing objective analyses in a wide range of technical areas.

Congress created OTA in 1972 to meet its need for a source of technical information that is nonpartisan, objective, and anticipatory. The office has been fulfilling this directive since it opened in 1974. In a recent interview John H. Gibbons, OTA's director, discussed the range of technical studies the office has undertaken during its first decade, and provided insight into the technical issues Congress will be grappling with in the coming years.

Gibbons was a professor of physics at the University of Tennessee and the director of its Energy, Environment, and Resources Center before returning to Washington to direct OTA in 1979. He had originally come to Washington in 1973 to organize the first energy conservation activities for the federal executive branch. Before that he had spent 19 years at the Oak Ridge National Laboratory, beginning as a research physicist and eventually directing ORNL's environmental program. Gibbons has published on topics ranging from experimental nuclear physics to the influence of energy price and technology on future energy demand.

What motivated Congress to create OTA?

Since I have directed OTA for only the past five years and the agency was a year old before I was even aware of it, let me tell you the history as I have learned it. In the late 1960s and early 1970s, Congress was receiving advice and so-called expert information on some very technical issues both from the executive branch and from outside witnesses, and many of these experts were absolutely disagreeing with each other. Members of Congress began to wonder whom to believe as an expert because it appeared that there were experts on all sides of an issue. It became obvious that Congress needed its own source of nonpartisan, in-house technical analytic help. As a result, Congress passed Public Law 92-484, which formed OTA to be an aid in the identification of technology applications. The legislation creating OTA was passed in 1972 and the agency actually got under way in 1974, so we are now completing our first decade. The first OTA director was Emilio Daddario, and the second was Russell Peterson. They headed the agency during the first five years.

What were some of the first studies that Congress requested from OTA?

Because the office was formed in the early 1970s, when congressional concern with technical issues was overwhelmingly focused on energy issues, probably 50%, if not 75%, of OTA's early activity was devoted to energy assessment. Thus OTA was primarily an energy-focused agency for the first five years. Its energy studies looked at both supply and conservation issues. The agency did a great deal of work helping Congress think out how the Department of Energy ought to be organized and what a federal role in energy should consist of. And there have been many OTA studies on energy-related legislation; for example, we have been working for several years on an assessment of what should be done with commercial high-level nuclear waste. Our initial work in this area was used as a basis for the passage of the 1982 Nuclear Waste Policy Act.

Early OTA studies provided an assessment of such energy issues as coal slurry pipelines, solar energy, residential energy conservation, biomass, nuclear power plant standardization, and the direct use of coal, to name a few. In more recent years we have published assessments on industrial energy use, potential U.S. natural gas availability, the federal coal leasing program, cogeneration, synthetic fuels and increased automobile fuel efficiency, acid rain, responses to a long-term energy shortfall, and the future of nuclear power. All these OTA publications are available to the public.

The only way we can undertake a study is through a request from a congressional committee—an individual member of Congress cannot request an assessment from us. The committees that originally made the most requests were the energy and environment, science and technology, and commerce committees, but by the end of the 1970s, more and more committees began turning to us for technical advice. We now get requests from the finance, budget, appropriations, judiciary, rules, and government operations committees, to name a few. As a result, studies are now spread across a broader range of issues, and energy now plays a continuing but relatively minor role—about 10% of our assessment agenda.

Are there any energy studies that OTA is currently undertaking?

Yes, there are a few, and two in particular may be of interest to your readers. We have under way an assessment of load management and generating technologies for electric utilities that discusses the constraints and opportunities utilities will face in choosing generating technologies in the 1990s. It is obvious that utilities are avoiding commitments to large new power plants because of the financial and regulatory problems associated with long lead times. OTA's assessment is attempting to determine if utilities perceive that other, smaller-scale technologies—such as fuel cells, photo-

Gibbons

voltaics, wind, low-head hydro, and utility-controlled load management—will provide important options for future utility systems. We hope to issue the final report this summer.

The other energy-related assessment in process is on the availability of U.S. natural gas and its potential for reducing the nation's dependence on oil imports. The purpose of this study is to determine domestic onshore natural gas supplies over the next few decades and to look at any factors that may affect availability.

How is OTA structured to carry out these technical studies?

The OTA staff is relatively small. There are approximately 100 professionals and 40 support staff. About half of the in-house staff are trained in science, engineering, and medicine, and the other half are trained in social science, law, economics, political science, and sociology—thus we have a very interesting mix of people. In addition to the in-house staff, we use an average of 50 contractors and consultants for each study, who come and go as the projects change.

We receive our funding from annual legislative appropriations, and our current budget is about $15 million. I would say that an average assessment costs about $500,000. We are now conducting some 30 assessments, and we take on 15 to 20 new projects each year.

Because of the variety of requests we receive from Congress, the organization of the agency constantly changes. We typically have nine program areas (under three divisions), each of which encompasses a major subject area—for example, energy and materials, oceans and environment, and food and renewable resources. I would say that on the average about one program a year changes its name to better reflect changing emphasis in some subject area. As a result, OTA staff members must have the ability to move from one subject to another and feel comfortable with it. We find that bright people who are oriented toward problem solving and quantitative analysis do pretty well at OTA, particularly those who enjoy variety and new challenges.

I have found that there are two things that really keep the staff on their toes around here. One is the great variety of work and the extremely tight demands for quality control; the second is the enormous flow of people and ideas through the place because of all the outside involvement. In addition to the outside experts and contractors that we use, we also establish an advisory panel for each study we undertake.

What is the function of these panels?

The advisory panels are asked only to tell us what we are doing right or wrong with our studies and to guide us along the way. The 12–18 members that typically make up these groups are chosen to represent a broad diversity of perspectives and backgrounds; they all come from outside the government, usually from universities, private firms, or research groups. For example, EPRI President Floyd Culler was a member of the advisory panel for commercial high-level nuclear waste assessment.

Advisory panels usually meet three to five times over the course of a two-year period, which is the typical length of our projects. In a panel's final meeting, it reviews and criticizes the draft report. We don't ask the members to formally approve or disapprove the report; we simply want to know what they think of it. We also do not want the advisory panels to be passive or disinterested bodies. We want them to forcefully express their opinions so that we hear a variety of viewpoints. We always pay a tremendous amount of attention to what they say; yet the advisory panels do not dictate to us. The final product must be ours, for we are the ones who send it to Congress.

How does OTA decide which congressional requests warrant assessment?

Thankfully, we have the Congressional Technology Assessment Board, a group of six senators and six representatives appointed by their leadership to review all the committee requests we receive. The board sets OTA's policies, selects its director, and is the exclusive governing body for its activities. The board is strictly bipartisan in that half of the members are Republican and half Democratic. The chairman and vice chairman are the senior person from the majority party in one house and the senior person from the minority party in the other house; the chair reverses every two years, with each change of Congress.

In the new 1985 Congress, the chairmanship moved from the House to the Senate; Ted Stevens (R-Alaska) is the new chairman and Morris Udall (D-Arizona) the new vice chairman. Other board members from the Senate are Orrin Hatch (R-Utah), Charles Mathias (R-Maryland), Edward Kennedy (D-Massachusetts), Ernest Hollings (D-South Carolina), and Claiborne Pell (D-Rhode Island). Other members from the House are George Brown (D-California), John Dingell (D-Michigan), Larry Winn (R-Kansas), Clarence Miller (R-Ohio), and Cooper Evans (R-Iowa). Winn is retiring from the House this year, and a replacement to the board will be named.

All board members must agree on every new assessment that OTA undertakes. Although they may disagree on specific issues—sometimes rather forcefully—or have different points of view about the studies, what the members have in common is a sense that nonpartisan analytic work is a very important thing for Congress to have available. Therefore, we find strong and continued bipartisan support for the work that OTA undertakes. And that's a great help to us.

At every quarterly board meeting, there are generally five separate requests from congressional committees for new assessments. The OTA staff will have already had extensive contact with each committee initiating a request to discuss the extent of the analysis needed and the timing of delivery. On the basis of these discussions, we present to the board a work strategy for each request. First the board will look at which committees are requesting studies to be certain that the issues are properly within their jurisdiction. Then it will consider a particular study, comparing it with other issues in terms of importance, and either approve or disapprove the request. Every now and then a request may come in that the board believes is not really a matter of technology; such a request would likely be passed over.

Does the board have to approve every report that OTA releases?

They approve the release of a report, but they don't take sides on whether they agree with the findings. They simply say that they have examined the process that OTA has gone through to carry out this study and they approve it for release. What the board wants to see is how we performed the work, how we constructed our advisory panel, who reviewed the work, and how we responded to those reviews. They want to know that we have gone through a stringent process to be certain that the work is of high quality and is as free of bias as we can get it.

Is there other oversight of OTA's work?

Yes, in addition to the board there are committees in both the House and the Senate that are charged with periodic review of the agency. Every few years, one or the other will hold an oversight hearing where we and others are called to testify. Outside witnesses, not only from Congress but also from universities and industry, are asked to tell what they think of OTA as an institution and how relevant its work is to their needs. Oversight is also provided by OTA's Technology Assessment Advisory Council, made up of 12 eminent intellectual leaders from universities, private industry, research companies, and other federal bodies.

In terms of the assessments themselves, is it difficult to keep the studies relevant when you are working in a two-year time frame?

Usually the assessments we undertake are so complicated and broad that the issues will be with Congress for long periods and therefore will not lose relevance by the time the results are published. When a committee requests a study, the chairman tells us when the information would be most useful, and we match our response to that time request. On the other hand, sometimes if a committee member needs the information promptly and there is not enough time to do a full assessment, we do what we call a special response. This is a more limited study tailored to what we can provide given the time constraints. We also provide interim reports, which can take a variety of forms, such as technical memoranda, background papers, case studies, briefings, and staff testimony.

The typical assessment, however, involves a complex issue. We have been working on acid rain, for example, for the past three years. We prepared several dozen special analytic papers during that time before publishing the final report, *Acid Rain and Transported Air Pollutants: Implications for Public Policy,* in June 1984. Since Congress is still pondering this issue, our work will probably go on for another year or two.

The information we are working on usually gets to Congress fairly quickly—within six months after we begin researching an assessment, we are often testifying before or briefing a committee on what we have learned. On the average, we testify about 50 times a year. In many cases a hearing will be organized around the completion of an assessment.

When the assessments are completed, does OTA make specific recommendations or advocate any position that the committee should consider?

In the typical assessment we tell the committee what informed people generally agree on about the issue, that is, what can be stipulated. Next we try to explain why people disagree with each other—why various experts come in with such disparate views on the same subject. Then we try to explain what options Congress has in light of what is agreed on, and which productive steps it could take if it chooses to do anything.

Sometimes, though not very often, we don't have that many different options to present in a study. Nuclear waste is a good example. In our assessment to Congress we said, you can choose to ignore this issue, but that isn't going to work. After listening to a variety of opinions and conducting our analysis, we finally said, if you want to do something about nuclear waste, here are the specific steps that will have to be taken to solve the problem. This assessment was rather unusual in that we were not able to give Congress a lot of options.

An example of a more typical assessment is a recent one on commercial biotechnology, in which we pointed out how the United States compares with other countries in the development of biotechnology. We discussed this country's relative strengths in the field and analyzed the role of government vis-à-vis the private sector in R&D and the commercialization of biotechnology. Our assessment suggested that if Congress feels it is important to give further encouragement to the development of biotechnology, there are certain steps that should be taken. Conversely, if Congress feels that the development is going too fast, there are some other steps that could be taken to constrain the activity. So we present all sides of an issue, and it is up to each individual congressperson to vote on the options. It is not our role to tell them how to vote. We simply provide the relevant facts and our analysis of available policy options.

You mentioned that energy is no longer the main topic of interest to Congress. What are the issues being addressed by current requests?

We receive a steady, perhaps increasing, number of requests in the environmental area. I think this reflects a strong American consensus that it is possible to have environmental quality as well as the necessary goods and services for a strong economy—that technologists can be clever enough to give us both. Some of our current environmental projects include analyses of the environmental compatibility of the federal coal leasing program, the cleanup of controlled hazardous waste sites, and ocean dumping of wastes.

Another area where there is tremendous interest from a variety of committees is the impact of telecommunications, microelectronics, and automation on such areas as privacy, intellectual property, regulation, international competitiveness, banking, personal lifestyles, employment, and education. Since the subject is so broad, an enormous number of committees are interested in its various aspects. Another large issue we are called on to investigate is the implication of the further development and use of sophisticated medical diagnostic equipment and life-sustaining techniques. This subject encompasses the dilemma of unlimited medical costs and the often conflicting goals of wanting to encourage the development of improved medical techniques to help people live fuller lives and yet, at the same time, not wanting to overcommit resources to extend a life that is no longer worth living. The question of medical ethics must be considered as well as medical technology. The health area is probably our largest program area at the present time. In fact, health and bioapplication issues are two of several areas in which we receive far more requests than we can handle.

To give some perspective on OTA's first decade, would you say the office has been able to adequately handle the technology assessment needs of Congress?

The sense we get is that they are generally pleased with what we are doing. I think they always hope to have more research for less money. Yet it is difficult to determine how completely we are fulfilling the original act that set up OTA—for the act is very brief and simply states that we should look at the implications, both positive and negative, of existing and emerging technologies in terms of their social, physical, biological, political, economic, and other impacts.

I also firmly believe that the need for technology assessment is growing because the great and vexing problems Congress has on its hands are driven in large measure by technology change—whether it be defense, employment, international competitiveness, or environmental issues. As long as that is the case, the members and committees of Congress will require some thoughtful analysis. They will need an organization and a process they can trust, a place where the gathering and distillation of national wisdom occurs.

And this is what I see as our continuing role in the future: to be a reliable and credible source for Congress. Also, I've found that to help Congress the most, you have to understand exactly what its needs are and tailor your delivery because it does not have the time for translation. You have to be very client-oriented if you hope to connect with this specific group of people.

If I had to define a particular task ahead of us, it would be to carry our analysis a little further beyond the technical side and a little closer to specific policy options. I think that sometimes we don't get close enough to what the committees and members of Congress need in terms of specific information to make their decisions. One reason is that although most of the people at OTA are highly trained in various disciplines, they are not that experienced in the legislative process. Conversely, the committee staff members are very close to the policy process but not to the technology issues. So what we try to do is to become attuned to what the committee members and staffers really need. This means there must be a great deal of communication between our professionals here at OTA and the staff members of the committees. And that is a key reason why we must be close to Congress, but not too close. Being housed six blocks away is just about right.

This article was written by Christine Lawrence, Washington Office.

EPRI Product Licensing Increases in 1984

New agreements make the LOMI solvent process and acoustic holographic imaging technology available for commercial development.

EPRI's goal of getting its research results into the hands of electric utilities made significant strides in 1984—the number of licenses issued by the Institute in the first three quarters of 1984 was more than the total issued in 1983. Through October EPRI had granted 44 licenses for hardware products, in addition to 9 commercial computer software licenses.

"Utilities, faced with today's squeeze of uncertain fuel supplies and rising costs, have a pressing need to obtain technical solutions without delay," says Don Erickson, EPRI's manager for Patents and Licensing. "Licensing, which gives utility suppliers the right to manufacture and sell EPRI-developed technology, is a vital step in providing new equipment and techniques to the industry."

Recent agreements on licensing rights with organizations outside EPRI have opened up two especially important technologies for future commercial development. The first of these gives the Institute the right to license the low oxidation-state metal ion (LOMI) solvent process to chemically decontaminate water-cooled reactors.

Initially, EPRI joined forces with England's Central Electricity Generating Board to develop the LOMI solvent. When EPRI's funding ended, CEGB continued work on the project and found a way to apply the solvent. EPRI now owns the patent on the product and CEGB, the application method.

Negotiations with CEGB on how commercial licensing agreements would be offered involved more than two years of transatlantic letters and telexes after the solvent and process had been discovered. According to the new agreement, EPRI is now the licensor of both the EPRI and the CEGB patents in the United States. This enables EPRI to license any qualified U.S. organization to market the LOMI process to utilities for decontamination services.

Another agreement, with the Gas Research Institute of Chicago, Illinois, is also an important one for the electric utility industry, as it allows EPRI to offer licenses on an acoustic holographic imaging technology. EPRI and GRI had separate research contracts with Spectron Development Laboratories to investigate this technology, which is able to make clear, life-size images of flaws in metal pieces, such as pipes, nozzles, and pressure vessels. The device, applicable to both electric and gas utilities, can also be used to map underground piping and evaluate stress concentrations.

When the research ended, EPRI and GRI decided to combine the results of the contracts into one package because this approach offered the best opportunity for commercial development. The agreement gives EPRI the right to offer licenses for the technology. In return for assigning its rights to EPRI, GRI will receive 25% of the royalties EPRI derives from third-party licensing arrangements.

EPRI's royalty income from this and all other licensing agreements is put into the general R&D fund. ■

Workshop on PCDFs, PCB Fluids

More than 50 scientists and engineers from universities, government, and the utility industry participated in a three-day workshop on polychlorinated dibenzofurans (PCDFs) sponsored by EPRI in early December. The purpose of the workshop was to give utility personnel a better understanding of the issues and questions surrounding PCDFs. Small amounts of PCDF congeners have been detected in insulating fluids containing polychlorinated biphenyl (PCB) fluids after fires in electrical equipment. Some, but not all, of the PCDF compounds have been found to be physiologically active in animal tests.

Because of current EPA regulations and public pressure, many utilities have replaced the PCB in their transformers and other electrical equipment with new insulating fluids. However, traces of the old insulating fluid that remain inside the equipment can bring the PCB level of the replacement fluid up to 2–5%. "In such cases, the new insulation is still legally considered a PCB fluid," explains Project Manager Gilbert Addis, who was cochairman of the workshop with Project Manager Ralph Komai.

Sessions at the workshop were held on analysis of PCDF; pyrolysis and combustion of PCBs; documentation of fires, spills, and clean-up; and risk assessment. Transmission Department Director Narain Hingorani presented a background paper on EPRI's Interdivisional Task Force, which is directing research into the chemistry of PCB fluids. One of the featured panelists at the workshop was Christoffer Rappe from the University of Umea, Sweden, who is recognized as one of the world authorities on PCDFs.

EPRI is currently funding two projects involving PCDF, and reports on these were included in the workshop. In the first study, researchers at the New York State Health Department are examining the oxidation characteristics of PCB fluids during normal combustion and during pyrolysis (a fire that takes place under low-oxygen conditions). Under the contract with EPRI, scientists are trying to learn the rate at which PCDFs are created from PCBs in retrofilled transformers involved in fires.

In the second project, scientists are evaluating and improving techniques to analyze the various PCDF congeners in insulating fluids used by electric utilities. "Following development of an improved analytic technique, a broad sampling of utility fluids will be analyzed so we will have a more detailed understanding of PCBs and how they relate to PCDFs," says Komai. ■

Energy Technology Conference Convenes in March

The 12th Annual Energy Technology Conference and Exposition (ET '85)—one of the nation's largest annual energy forums—will be held March 25–27, 1985, at the Sheraton Washington Hotel in Washington, D.C. Designed for electric utilities and their industrial and commercial customers, ET '85 will offer 80 conference sessions with more than 250 speakers. This year's meeting will focus on issues between the utility and the industrial customer.

There will also be more than 250 exposition displays on energy technology applications and developments throughout the United States, Canada, and the world. EPRI will join many leading companies in the energy industry with a display of its research innovations and applications and will sponsor a film/video theater on the results of its research programs.

John R. Miller, president of Standard Oil Co. of Ohio (Sohio), will present the 1985 State of Energy message to keynote the conference on Monday morning, March 25. The conference will conclude Wednesday afternoon, March 27, with an energy prospectus session chaired by EPRI Vice President Richard Rudman. This closing session will feature a talk by C. Fred Fetterolf, president of Alcoa, and a talk by a representative from the Energy Information Administration.

A number of EPRI staff members will participate in ET '85, either as speakers or session chairmen, on such topics as fluidized-bed combustion research, power plant life extension, improved plant performance, combined-cycle power plants, electrotechnologies and electrification, utility automation and load management technology, demand-side management options, supply and reliability, commercialization of new energy technologies, and acid rain control technologies.

Participating on the ET '85 program advisory committee are Rudman and Michael Tinkleman of the Washington Office. Christine Lawrence, communications supervisor in the Washington Office, is coordinating publicity.

Full details are available from Government Institutes, Inc., 966 Hungerford Drive, No. 24, Rockville, Maryland 20850. The telephone number is (301) 251-9250. ■

Guidelines for Control Room Computer Displays

The Nuclear Power Division has published a two-volume study to help utilities design and evaluate computer-generated information displays in nuclear power plant control rooms. Entitled *Computer-Generated Display System Guidelines* (NP-3701, 2 vols.), the set provides a step-by-step procedure for designing and testing display systems before installing them in nuclear power plants.

"Computer-generated displays can help improve the flow of operating information between the operator and plant," explains John O'Brien, project manager. "Their flexibility in terms of display format and information organization cannot be approached by hard-wired instruments. They also offer display system designers new opportunities for creative solutions to control room information problems."

For such systems to be effective, O'Brien cautions that the correct information about the plant must be presented to the operator at the right time, and the displays must be easily read and understood. Therefore, the report emphasizes human factors in designing and evaluating displays. In addition, the study gives special consideration to retrofitting computer-generated displays into control rooms where hard-wired analog instrumentation is the primary means of information display.

"EPRI published the report because the method of sending operation information to the plant operator is in a state of transition," says O'Brien. "Conventional hard-wired meters and dials are slowly being supplemented—in a few cases even supplanted—by video display terminals." This transition has been accelerated as more utilities decide to use video display screens to satisfy NRC requirements for a safety parameter display system. For the future, suppliers are marketing advanced control room designs with video display screens as the primary way to send information to the operator. One such advanced control room is now operating at the Susquehanna plant of Pennsylvania Power & Light Co.

For more information, contact O'Brien at (415) 855-2214. ■

CALENDAR

For additional information on the EPRI-sponsored/cosponsored meetings listed below, please contact the person indicated

JANUARY

16–17
Regional Conference: Compressed-Air Energy Storage
New Orleans, Louisiana
Contact: Robert Schainker (415) 855-2549

29–30
Workshop: Hazards Program
Denver, Colorado
Contact: Carl Stepp (415) 855-2103

FEBRUARY

4–6
Seminar: Nuclear Safety Control Technology
Palo Alto, California
Contact: Murthy Divakaruni (415) 855-2409 or K. H. Sun (415) 855-2119

26–27
Continuous Emissions Monitoring, Guidelines Manual
Atlanta, Georgia
Contact: Charles Dene (415) 855-2425

MARCH

6–7
Seminar: Maintaining Equipment Qualification
Houston, Texas
Contact: Robert Kubik (415) 855-8905

20–21
Continuous Emissions Monitoring, Guidelines Manual
Denver, Colorado
Contact: Charles Dene (415) 855-2425

APRIL

9–11
Seminar: Power Plant Digital Control Using Fault-Tolerant Computers
Phoenix, Arizona
Contact: Murthy Divakaruni (415) 855-2409 or K. H. Sun (415) 855-2119

14–19
Conference: Coal Gasification and Synthetic Fuels for Power Generation
San Francisco, California
Contact: Sy Alpert (415) 855-2512

16–17
Seminar: Maintaining Equipment Qualification
Washington, D.C.
Contact: Robert Kubik (415) 855-8905

30–May 2
Hydro O&M Workshop and Seminar: Dam Safety
Boston, Massachusetts
Contact: James Birk (415) 855-2562

MAY

6–9
1985 Joint Symposium on Stationary Combustion NO_x Control
Boston, Massachusetts
Contact: Michael McElroy (415) 855-2471

7–8
Seminar: Maintaining Equipment Qualification
Chicago, Illinois
Contact: Robert Kubik (415) 855-8905

12–18
Workshop: Exploratory Research on Amorphous Materials
San Diego, California
Contact: Robert Jaffee (415) 855-2453

14–15
Regional Conference: Compressed-Air Energy Storage
Chicago, Illinois
Contact: Robert Schainker (415) 855-2549

JUNE

18–21
Symposium: Condenser Biofouling Control
Orlando, Florida
Contact: Winston Chow (415) 855-2868

26–27
Seminar: Maintaining Equipment Qualification
Palo Alto, California
Contact: Robert Kubik (415) 855-8905

Pollution Control Hotline Lowers Fuel Costs at Lilco

A potentially expensive emissions problem at Long Island Lighting Co.'s (Lilco) Northport plant has been avoided with the aid of the Quick Response Inquiry (QRI) pollution control consulting service managed for EPRI by Battelle, Columbus Laboratories. Complaints about sulfurous odors from the plant raised the possibility of an expensive switch to low-sulfur fuel oil to avoid SO_2 production. But QRI staff helped Lilco environmental engineers trace the odor to H_2S or COS. By avoiding an expensive plume-chasing program and by allowing Lilco to continue using high-sulfur oil, QRI helped to save the utility an estimated $261,000. ■ *QRI Hotline: Joseph Oxley at Battelle, Columbus Laboratories (614) 424-7885* ■ *EPRI Contact: Charles Dene (415) 855-2425*

Stack Design Guidelines Save LADWP $4.5 Million

Guidelines on the design and operation of wet-stack systems, developed for EPRI by Dynatech R/D Co., can help utilities reduce costs by avoiding liquid re-entrainment in the most efficient way. Sometimes a flue gas reheat system can be eliminated altogether. When Los Angeles Department of Water & Power (LADWP) was designing its Intermountain Power Project generating station, for example, the guidelines provided critical parameters related to design of the stack. LADWP learned that the Intermountain stack would not be compatible with wet operation unless it was redesigned to a larger diameter, which was not feasible. The utility thus chose to incorporate moderate stack gas reheating to maintain a dry stack. By optimizing the system, LADWP was able to avoid probable corrosion problems and an expensive retrofit for a saving of approximately $4.5 million in capital and operating costs. ■ *EPRI Contact: Charles Dene (415) 855-2425*

Cost of Fuel Channel Replacement Cut in Half

Fuel bundles in a boiling water reactor (BWR) are held in place by rectangular Zircaloy channels, which deform slightly because of pressure differentials and irradiation. These channels have a design lifetime that coincides with replacement of the fuel bundles (about four or five years), but inspection of the channels suggested to Commonwealth Edison Co. that some channels could be reused for a second fuel load. Using channel management methods developed for EPRI by Dominion Engineering, Inc., the utility measured channel regularity and estimated future deformation. This work showed that about one-third of the channels could be reused and that the cost of channel replacement could be cut roughly in half. Commonwealth Edison estimates a saving of approximately $371,000 for each of its BWR units, plus further saving from reduction of irradiated materials that need disposal. ■ *EPRI Contact: Joseph Santucci (415) 855-2011*

Miniature X-Ray System Speeds BWR Weld Inspection

Philadelphia Electric Co. has used a newly developed miniature X-ray system to perform otherwise unachievable weld inspections at its Peach Bottom Unit 3 BWR. The portable X-ray head is sensitive enough to allow inspection of welds in large-diameter pipes without draining cooling water, saving time during fuel replacement outages and money for replacement power. The new system, a further refinement of the Minac miniature linear accelerator, was developed under an EPRI agreement by Schonberg Radiation, Inc. The unit consists of a detachable, portable X-ray head attached to Minac by a flexible waveguide. With it, personnel are able to inspect piping welds in the restricted areas close to the reactor pressure vessel. Philadelphia Electric estimated that without the device a recent in-service weld inspection would have taken an additional two days and cost an extra $1 million for replacement power. ■ *EPRI Contact: M. E. Lapides (415) 855-2063*

New Analysis Methods Enhance Substation Safety

Improved safety and lower costs—these are the benefits cited by Arizona Public Service Co. (APS) from use of a new set of analysis techniques for designing substation grounding systems. Developed at Georgia Institute of Technology's Electric

Power Laboratory, the new methods go beyond the limitations of the IEEE Standard 80 guidelines used previously. The system uses advanced analytic methods, graphic techniques for common design problems, and computer-based solutions for complex structures, and it combines these elements into an analysis package for design engineers. APS engineers say the system enables more-accurate design, providing greater confidence in the safety of the ground system and requiring less use of copper than older, more-conservative methods. Design is faster, too, allowing APS to reanalyze existing stations. Altogether, APS estimates the improved methods will save $82,000 over the next 10 years in material costs alone. But they add the money is not as important as the improved safety for operating personnel. ■ *EPRI Contact: John Dunlap (415) 855-2305*

Static VAR Generator Helps Supply Remote Load

Large, isolated loads can pose serious stability problems for transmission systems, but a new static VAR compensator designed by Westinghouse Electric Corp. under EPRI contract helped Plains Electric Generation Transmission Cooperative, Inc., solve just such a problem recently. Plains saved $22 million by using the new compensator to help supply a 50-MW load at an oil-field compressor station in a remote area of New Mexico. The new load was 90 miles (145 km) from the nearest 115-kV substation, but without the VAR compensator, Plains would have been forced to build a new 200-mile (322-km), 345-kV line from its system to meet the startup demand. Instead, Plains was able to use the compensator and meet the load from the closer substation with a $6 million, 115-kV line. Overall saving—$22 million, and Plains engineers say the added compensation provides more stability to the whole transmission system. ■ *EPRI Contact: Gilbert Addis (415) 855-2286*

Texas Facility Provides Sophisticated Tower Testing Capability

The Transmission Line Mechanical Research Facility (TLMRF) in Haslet, Texas, is a sophisticated facility dedicated to determining all structural aspects of tower performance. It can also be a cost-competitive way of evaluating new tower designs, as Public Service Co. of New Mexico (PSNM) discovered when it was developing a new series of structures for a 216-mile (35-km) 345-kV line. PSNM estimates saving $30,000 because TLMRF allowed it to keep to a tight schedule. At the same time it gained higher-quality data on tower design and was able to avoid reliance on the vendor's test facility. TLMRF is one of several technology transfer centers launched by EPRI in recent years, using information gained with its state-of-the-art instrumentation to build a reliable data base on all types of tower designs. By making that information available to utilities, TLMRF is contributing to improving designs and cutting costs for future transmission projects. ■ *EPRI Contact: Paul Lyons at TLMRF (817) 439-5900*

System Simulation Model Saves Time, Money at Con Ed

A sophisticated new fast-turnaround system planning computer model is saving Consolidated Edison Co. of New York (Con Ed) about $200,000 per year in planning study costs. With TELPLAN, a computer model developed by TERA Corp. under EPRI contract, Con Ed can run a complete generation addition simulation in one day. This allows the utility's planners to model hundreds of scenarios with varying cost, environmental, and financial factors. By performing these simulations in-house and at this speed, Con Ed can do scenario analysis of a type that was impossible using older, slower techniques. "There is not even a comparison with other systems," says Wayne A. Vanderschuere of Con Ed. TELPLAN uses state-of-the-art probabilistic production cost methods, simulates the entire power supply system, and integrates the results with financial plans and pollution control constraints. The model is largely machine-independent and can run on PRIME, VAX, CDC, and IBM computers. ■ *EPRI Contact: Dominic M. Geraghty (415) 855-2601*

Cilco Improves Scrubber Performance for NSPS Compliance

Where can utilities turn for information when new flue gas desulfurization (FGD) equipment fails to perform adequately? EPRI's continuing research on FGD chemistry may be able to provide some answers on how to improve both pollution abatement and system reliability. Central Illinois Light Co. (Cilco), for example, found help in solving problems at its new Duck Creek Generating Station, where a wet-limestone FGD system could not consistently meet the New Source Performance Standard (NSPS) for sulfur dioxide removal. In addition, the scrubber was experiencing mist eliminator scaling and low limestone utilization. Using information from ongoing projects and working with EPRI contractor assistance, Cilco adjusted the limestone particle size and added relatively small amounts of dibasic acid to meet NSPS requirements while increasing system reliability to over 95% and reducing maintenance labor requirements by 30%. ■ *EPRI Contact: Dorothy Stewart (415) 855-2609*

Editor's Note
We have launched this new department as part of EPRI's growing commitment to technology transfer. It will focus on applications of EPRI-sponsored research, new commercial products, and new licensees. We want this department to evolve in ways that best meet your needs, and we would appreciate hearing from you.

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

FUSION BLANKET ENGINEERING TESTS

In first-generation fusion power systems as now conceived, the fuel would be a combination of deuterium and tritium, two isotopes of hydrogen. Eighty percent of the energy produced by "burning" the fuel will be in the form of kinetic energy of neutrons. It is proposed that this energy be converted into thermal energy in a blanket surrounding the fuel. In addition, neutrons are to be absorbed in lithium in the blanket to produce replacement tritium for the primary fuel. To date most fusion research has been concerned with producing burning conditions in plasmas. The next advance would involve transforming the fusion energy captured in a blanket into useful heat.

A major issue in work on blanket systems will be the blanket's ability to breed tritium for fuel supply self-sufficiency. The TFTR (tokamak fusion test reactor) facility at the Princeton Plasma Physics Laboratory offers the first opportunity to examine this issue experimentally with burning fusion fuel (Figure 1). This DOE facility, which has been operating with proton-based hydrogen since December 1982, will begin using deuterium late this year. Under a contract with Princeton (RP1748) and in cooperation with DOE, EPRI has initiated a project to conduct lithium blanket engineering tests at the facility. A prototypical blanket module for the tests is under construction at General Atomic Co., a project subcontractor.

The TFTR, which has a toroidal (doughnut-shaped) fuel chamber, is designed to burn deuterium-tritium (D–T) fuel and is capable of producing tens of megawatts of fusion power for approximately one second. It will have a geometrically extended neutron source and a neutron spectrum similar to that expected in an ultimate fusion power system. Even during operation with deuterium only, the neutron spectrum can be useful in determining the ability of a blanket module to breed tritium. To date complex neutron scattering and absorption calculations provide the only estimates of this ability. In the absence of corroborative measurements, there are large uncertainties in the estimates of breeding ratios because of the complex geometry and codes involved. At this time, the overall breeding rates in the central rods of the lithium blanket module (LBM) can be calculated to 12% accuracy, but there is no experimental verification. EPRI initiated the LBM experiment to develop data to minimize these uncertainties and evaluate the ability of fusion systems to be self-sufficient in tritium.

The central activity of this program is the irradiation of a lithium-containing assembly representative of a fusion reactor blanket module. Measurements of neutron fluence and energy distribution throughout the LBM, as well as of tritium production, will be compared with predictions by three-dimensional neutronics codes. These comparisons will indicate the effectiveness of currently available analytic techniques and physical models in describing the performance of single blanket modules in toroidal reactors and will identify needed improvements.

Another program objective is to obtain, for the first time, hands-on experience in several critical areas of fusion blanket technology, including the fabrication of breeding elements, blanket dosimetry measurement in a tokamak reactor environment, the electromagnetic isolation of blanket modules from the pulsed tokamak fields, and the integration of a blanket module into a test reactor.

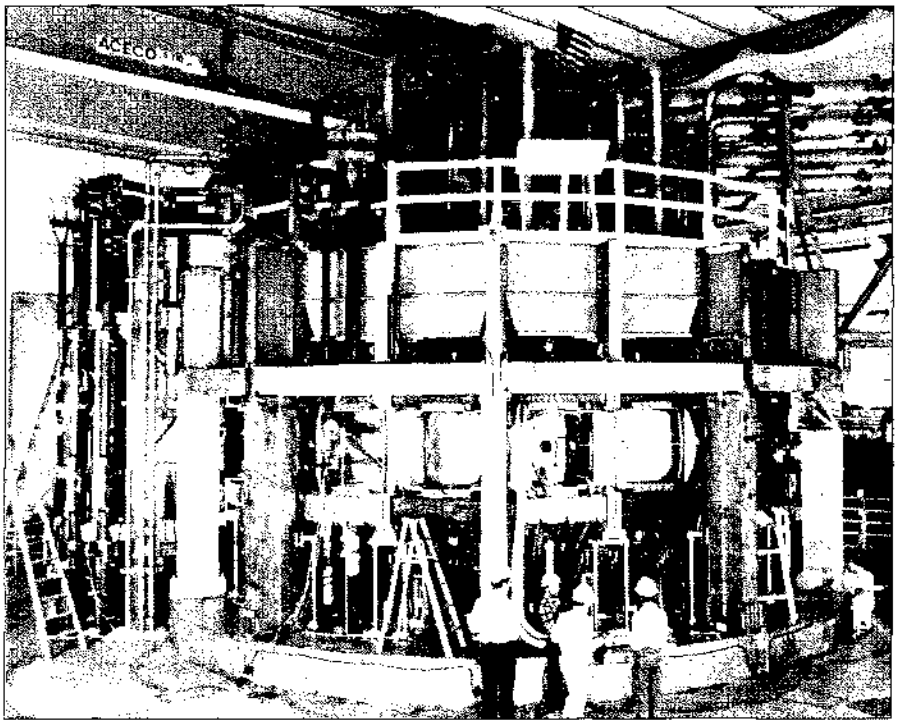


Figure 1 The TFTR at the Princeton Plasma Physics Laboratory. This large DOE fusion facility began operation in late 1982 and is now being modified to use deuterium with neutral beam heating.

Test equipment

During deuterium operation at the TFTR, the LBM will be positioned close to the reacting toroidal chamber. An engineering test stand has been constructed for this purpose. The LBM will not be attached to the TFTR, and no interference with other facility activities is expected. The LBM will be placed on a movable pallet on the test stand, which will permit limited remote manipulation.

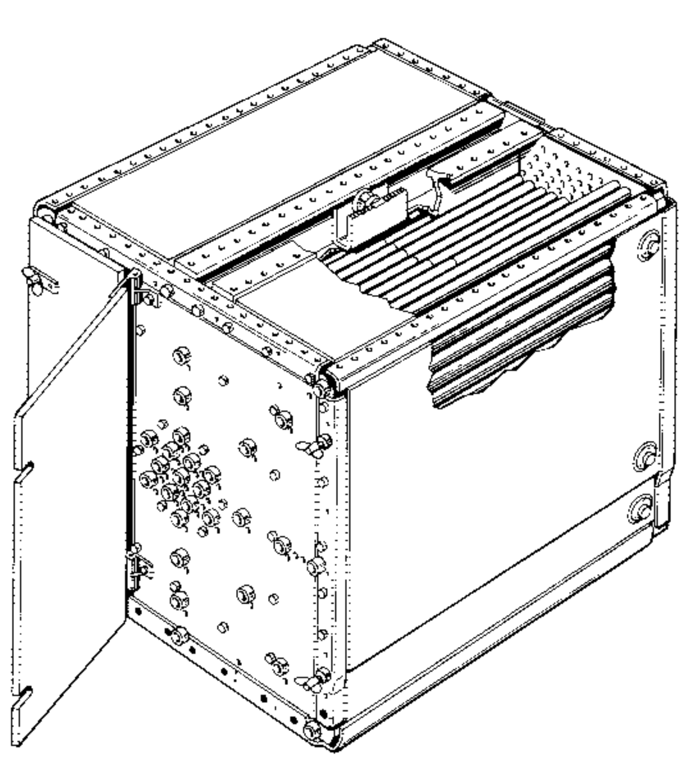
The blanket module (Figure 2) features an array of approximately 920 cylindrical breeder rods oriented radially to the plasma surface. Each rod, a stainless steel tube with an outer diameter of 2.54 cm and a wall thickness of 0.3 mm, contains 22 or 23 lithium oxide (Li_2O) pellets. The rod assembly consists of two zones. A central zone 19 cm in diameter contains 37 rods and 25 dosimeter wire bundles; 13 of the rods are instrumented and can be removed individually from the back of the module. A buffer zone contains the main body of rods, approximately 900, and serves to isolate the central zone from scattered neutrons entering the sides of the LBM. This zone is lightly instrumented, and selected rods are removable.

There were several reasons for deciding to orient the rods radially to the plasma. Many LBM program objectives can be defined in terms of breeding along a single rod. Also, this arrangement lends itself to a reactor-relevant cooling system, wherein gas or water coolant would flow to the front face of the module (the region of highest power deposition) and then flow back between the breeder rods. Finally, the arrangement facilitates equipment handling. Test personnel can easily install or replace radiation dosimetry wires in the channels between rods; remove breeder rods from the back of the LBM to retrieve test pellets and dosimetry packets; and replace central-zone rods with rods containing different materials.

The rods are tightly arranged so that groups of three form channels 6 mm in diameter. Neutronics calculations have determined that neutron streaming along these tricusp channels will have an insignificant effect on spatial neutron flux and tritium production.

Li_2O was chosen as the breeding material for the LBM because of its potential for adequate tritium breeding without a neutron multiplier and because its physical and chemical properties are acceptable for reactor use, at least up to 600°C. Pellet fabrication involves weighing Li_2O powder and loading it in a die, cold-pressing it at pressures as high as 20,000 psi (138 MPa), and then sintering the pressed pellet in a vacuum at 1000–1200°C for up to 12 hours. After fabrication, pellet microstructure and impurity content (mainly carbon dioxide and water) are characterized. Researchers have found that pellets of about 80% of theoretical density can be obtained by cold-pressing the powder at just 10,000 psi (69 MPa) and sintering the cold-pressed pellet in a vacuum at 1200°C for 12 hours. Metallographic examination has indicated that the microstructure of these pellets is uniform and reproducible.

Figure 2 Lithium blanket module. Such a module, measuring 76 by 79 by 89 cm, is being built for use in tritium-breeding experiments at the TFTR. The module's 920 breeder rods, each filled with Li_2O pellets, will be oriented radially to the TFTR plasma.



Procedures have been developed for mass-producing Li_2O pellets 2.45 cm in diameter and 2.54 cm long, and some 25,000 pellets are now being manufactured for assembly into the LBM. The process features an automated press with a hopper-feed capability and a tungsten carbide die for cold-pressing and a cold-wall vacuum furnace for sintering. Strict control of the Li_2O powder size distribution is essential to ensure that the sintered pellets meet the specifications for density and diameter.

Some 900 LBM prototype breeder rods have been fabricated from type-316 stainless steel tubing 0.3 mm thick. The rods were assembled in air and were determined to be leak-free after welding. Tests have shown that the rate of moisture and carbon dioxide pickup by the sintered Li_2O pellets under ambient conditions (50% relative humidity) is so small that it is feasible to load and seal the breeder tubes in air.

It is estimated that 24 hours after the LBM has been exposed to the radiation from the neutron fluence in the highest-power D–T case at the TFTR (10^{13} neutrons/cm^2 per run of 10 shots), the activity on the LBM front grill plate will be about 4 mrem/h. The activity of a single breeder rod will be much less than 1 mrem/h and will continue to drop rapidly with time. Thus remote handling equipment will not be necessary for working with the test rods. After a 48-hour cooldown period, it will be permissible to remove the LBM from the engineering test stand with manually operated cranes and a forklift.

Measurement and analysis program

Measurements from the LBM engineering tests will be compared with predictions from neutronics analyses. Project personnel will monitor dosimeter activations at various positions inside the LBM and on its surface, and will measure tritium production at various positions inside the LBM central region. Parameters that can be derived from these measurements include the local tritium breeding ratio, the tritium production ratio, total neutron fluence and its gradient, and (by use of the FERRET adjustment code) the fluence and gradient for each neutron energy group.

The MCNP code, developed by Los Alamos National Laboratory, and the ENDF/B–V pointwise cross sections have been used to carry out detailed three-dimensional Monte Carlo simulations of the TFTR–LBM system for both D–T and deuterium-only toroidal neutron sources. The use of specialized techniques in the MCNP model (e.g., 45° reflection planes) and of conservative variance reduction techniques (e.g., geometry splitting and survival biasing) allows meaningful statistical accuracy (±10% or better) to be obtained for parameters for the entire LBM by calculating 20,000 neutron histories. The overall uncertainty in calculating the gross tritium breeding ratio for a central-zone LBM rod is approximately ±12%; this figure takes into account the Monte Carlo calculation statistics, the TFTR and LBM modeling, the cross-section uncertainties, and the independent systematic uncertainty in the neutron source configuration.

A dosimetry qualification program has been conducted at EG&G Idaho, Inc. Feasibility demonstration experiments have been performed with dosimeter foils irradiated in the CFRMF (coupled fast reactivity measurements facility) to simulate the neutron spectra in the LBM during deuterium-only operation of the TFTR plasma. To investigate candidate dosimeter materials for D–T operation of the plasma, EG&G used a blanket simulation facility featuring a 14.1-MeV point neutron source and a lithium carbonate and stainless steel mockup of the LBM.

In the tests at the TFTR, the activation levels of foils and wires will be evaluated after each run by gamma-ray spectrometers using germanium or lithium detectors, sodium iodide well detectors, and sodium iodide scanners. The unique dependence on energy of the activation cross section for each material allows the fluence of each neutron energy group to be determined by an adjustment (unfolding) code, such as FERRET. Taking into account uncertainties in cross sections and in counting rates, the dosimetry demonstration experiments showed that the fluence of the source neutrons (i.e., the 14-MeV group) can be determined to ±9% or better if their fluence at the measurement position is at least 5 × 10^{10} neutrons/cm^2 per run. For lower-energy neutron groups, fluences can be measured to better than ±20% at positions on or near the LBM surface and to ±30% at positions throughout the LBM, provided that certain conditions regarding total neutron fluence per run and dosimeter retrieval are met.

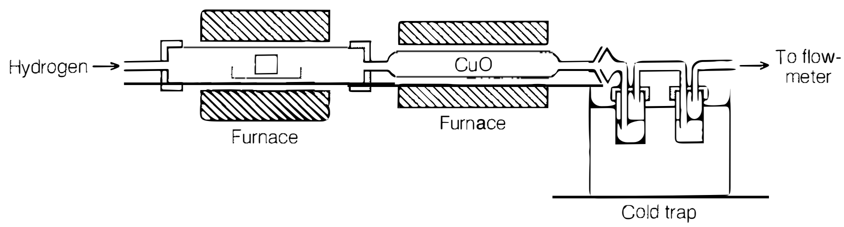


Figure 3 Thermal extraction method for collecting tritium bred in Li_2O pellets. The pellets are heated in a furnace tube at 700–1000°C for 4–6 hours in a stream of hydrogen. The tritium boils off and is carried by the gas into a second furnace, containing copper oxide heated to 500°C. There tritium and hydrogen oxidize to form water vapor, which is then condensed in a cold trap (−60°C). By measuring the amount of water that forms and its activity, tritium production can be determined to about ±6%.

Three methods of extracting tritium from the LBM pellets have been evaluated analytically: aqueous dissolution, flux extraction, and thermal extraction. The study predicted that the thermal extraction method (Figure 3) would result in the lowest uncertainty in determining the small tritium concentrations generated in the LBM breeder pellets after each deuterium or D–T run (0.1 to 10 nCi per gram of lithium, or 10^{10} to 10^{12} atoms of tritium per pellet). A tritium assay laboratory that will use the thermal extraction technique is being assembled at Princeton.

The ongoing tritium analysis qualification program indicates that the systematic error incurred in extracting and counting tritium from Li_2O pellets can eventually be reduced to approximately ±4%. The combined random uncertainty for the analysis of a single pellet is about ±4.6%; this can be halved by analyzing four pellets at comparable positions and with the same radiation exposure. Then the total uncertainty in the tritium measurements (i.e., the sum of the systematic and random errors) can conservatively be taken as about ±6.3%. As noted earlier, the overall uncertainty associated with predictions of tritium production is ±12%.

Project status

The engineering test stand has been constructed and is ready for installation at the TFTR. Module construction and pellet fabrication are under way, and the LBM is expected to be completed for delivery to Princeton in May 1985. The original TFTR schedule called for deuterium operation to begin in the summer of 1985 and for the use of tritium to be phased in during 1986, concluding with 10 shots of 50% D–T in late 1986. However, recent federal program changes may delay tritium use until late 1988.

The effect of this delay on the LBM project has not yet been fully evaluated. However, there are several project options. One is to follow the current schedule through deuterium operation of the TFTR, during which preliminary tritium production data would be obtained and compared with calculations, and then store the LBM until tritium is used at the facility. A second, less desirable option is to test the LBM in another facility during 1985–1986 while the TFTR prepares for tritium use. A third option is to complete the module and mothball it until the federal program initiates a tritium bum in the TFTR.

In view of the delay at the TFTR, it is fortunate that preliminary data can be obtained during deuterium-only operation. However, the logical completion of the LBM project depends on the use of tritium as a fuel in that or another fusion facility. *Program Manager: F. R. Scott*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

COAL CLEANING TEST FACILITY

*The broad mission of EPRI's Coal Cleaning Test Facility (CCTF) in Homer City, Pennsylvania, is to advance state-of-the-art coal-cleaning technology. Characterizing the effects of coal cleaning on major U.S. steam coals and in developing and demonstrating coal-cleaning equipment, CCTF is a proving ground for coal-cleaning and dewatering technologies, instrumentation and process control strategies, and ancillary equipment. Each year EPRI's Fuel Quality Program management and CCTF advisory committees—composed of representatives from utilities, coal companies, architect/engineers, universities, and government—review CCTF objectives and plans. Two earlier status reports describe the capabilities and operation of the facility (*EPRI Journal*, December 1982 and December 1983). This report focuses on CCTF's contributions to the advancement of the overall understanding of coal and coal-cleaning technology.*

Coal cleanability characterizations

Since beginning operation in late 1981, CCTF has characterized the effects of coal cleaning on 15 bituminous and 2 subbituminous coals. A coal cleanability characterization (a series of tests that quantifies a coal's susceptibility to physical coal-cleaning processes) allows a utility or coal company to design better cleaning plants, operate existing plants more efficiently, and make timely, sound decisions about coal quality and combustion alternatives.

These characterizations, which are a major part of CCTF work, have already benefited utilities. Pennsylvania Electric Co. and New York State Electric & Gas Corp., two of CCTF's cofunders, estimate that by supplying engineering data and test results that are directly applicable to their full-scale cleaning plant at Homer City, CCTF will save them $68.7 million in revenue requirements over the next 30 years. The utilities owning the Conemaugh power plant (which include seven EPRI members) affirm that CCTF information allowed them to bring their plant on-line sooner at a savings of $3.75 million.

There are four parts to determining a coal's cleanability: characterizing the raw coal, investigating impurity liberation, evaluating the coal-cleaning processes, and comparing combustion characteristics.

Characterizing raw coal defines the as-received quality of a coal. Physical and chemical analyses provide the information for assessing the theoretical cleanability of the coal in its raw state. These comprehensive data have many uses beyond improving the accuracy of cleaning-plant design by determining the quantities of various sizes of coal that must be treated in separate cleaning circuits within the cleaning plant. For example, summaries of the coal size distributions have influenced the design of coal feed systems for fluidized-bed combustors, and proximate analyses of coals tested at CCTF have been used in a study of precipitator performance.

Investigating impurity liberation defines how much of a coal's ash and sulfur particles is freed as the coal is crushed to progressively finer top sizes. Crushing tends to unlock the impurities from the coal particles, thereby increasing the effectiveness of physical coal cleaning. Data obtained from the liberation test matrix allow any potential user of a coal to select the top size that best meets quality and size requirements. In tests of a representative sample from a 560-ton lot of Illinois No. 6 seam coal, CCTF showed that crushing run-of-mine coal to ¼-in top size can reduce the sulfur dioxide emission potential of clean coal from 5.0 to 4.5 lb/MBtu at a constant 95% energy recovery. However, CCTF tests on Stockton-Lewiston seam coal from Kanawha County, West Virginia, reveal that the sulfur is so finely dispersed in this coal's particles that crushing the coal to ¼-in top size does not free additional sulfur.

Evaluating the coal-cleaning processes (flowsheet tests) assesses the performance of commercial-scale coal-cleaning equipment and the changes in coal characteristics brought about by cleaning. Flowsheet tests allow engineers to determine empirically the effectiveness of the flowsheet and the cleaning and dewatering equipment. Simulating fine (−¾-in top size) coal-cleaning flowsheets at CCTF gave Buckeye Power, Inc., accurate equipment performance data and coal sample analyses for verifying a proposed cleaning-plant design. Flowsheet tests also provided Cincinnati Gas & Electric Co. the necessary data for assessing the benefits of cleaning one of its coal supplies, and similar tests gave the Tennessee Valley Authority the information needed to improve the performance of an existing cleaning plant. In addition to these benefits, flowsheet tests also supply large, representative samples of coal cleaned to different quality levels for laboratory studies, combustion tests, and other research.

Comparing a coal's combustion characteristics measures changes in combustion-related parameters from the coal's raw state through liberation and cleaning to various quality levels. This evaluation, which assesses coal's expected combustion performance, can be valuable in identifying potential problems for utilities. Although commonly used indexes and combustion performance precursors are incomplete and lack precision, they do allow a fairly accurate comparison of different coals and different quality levels of cleaned coal derived from a given raw coal. For example, pilot-scale combustion tests verified CCTF combustion data on Illinois No. 6 seam coal, demonstrating that slagging was progressively reduced when coal was cleaned to two different quality levels.

Table 1 lists the 1984 coal cleanability tests as well as each test's objectives. Member utilities are the primary source of coals tested at CCTF. A utility typically donates 1000 tons of coal for characterization, development, and demonstration, as well as for additional tests specifically designed to satisfy that utility's objectives. Using the annual CCTF test plan as a guide, the utility and CCTF staff design a test program for each coal to meet both CCTF and utility objectives. Each test program is then systematically conducted to obtain reliable, accurate data. For each coal characterization, CCTF issues an informal report of results to the

Table 1
CCTF 1984 COAL CLEANABILITY CHARACTERIZATION TESTS

Test Period	Coal Seam (state)	Coal Supplier	Major Objectives	Coal Supplier Benefits
January and February	Lower Kittanning (Pennsylvania)	Pennsylvania Electric Co. New York State Electric & Gas Corp.	Determine heavy-media cyclone performance as a function of mounting angle	Determine whether the dry volatile content of the coal can be increased from 16 to 20% by preparation
March and April	Kittanning C-split (West Virginia)	Boston Edison Co.	Compare two-stage water-only cyclone performance in rewash and secondary overflow recirculation configurations	Provide coal quality and handling data for use in coal-purchasing decisions
May and June	Kentucky No. 9 (Kentucky)	Tennessee Valley Authority	Determine heavy-media cyclone performance as a function of magnetite grade	Demonstrate fly-ash-derived magnetics and yield-quality relationship at three sulfur levels
July and August	Lower Freeport (Pennsylvania)	Pennsylvania Electric Co. New York State Electric & Gas Corp.	Conduct flowsheet tests on actual coal blocks sampled extensively by both core and channel sample methods	Provide data needed to develop models for predicting raw and clean coal characteristics from core hole data
September	Hub (Nova Scotia)	Canadian Center for Mineral and Energy Technology and the International Energy Agency	Investigate separately the maximum sulfur reduction and maximum energy recovery possible in heavy-media flowsheets	Provide samples of raw and clean coals for combustion tests
September and October	Pittsburgh (Ohio)	Cleveland Electric Illuminating Co.	Investigate sulfur reduction potential by cleaning both crushed and natural raw coal fines	Evaluate coal cleanability to meet current and proposed emissions standards
November and December	Lower and Middle Kittanning (Pennsylvania)	Boston Edison Co.	Investigate relationships of clean coal sulfur and ash versus product yield	Develop a strategy for optimizing SO_2 scrubber operating costs and coal costs

sponsoring utility, and EPRI publishes the more formal *Campaign Report* for the electric utility industry.

Development and demonstration

Each year CCTF staff evaluates potential coal cleaning and dewatering, instrumentation, process control, and associated projects on the basis of each one's potential benefits, interest to utilities, probability of success, and compatibility with CCTF's fundamental objectives and available resources. They develop a test matrix for each selected project and then refine the matrix on the basis of initial testing experience.

In many cases the test objective is to characterize the performance of a given piece of equipment to a level of detail adequate for developing a model to fully understand its operation. For example, CCTF is conducting more than 30 tests to assess the dewatering performance of a high-g centrifuge (Figure 1). The tests measure moisture reduction and power consumption in relation to throughput capacity, feed size distribution, and feed ash con-

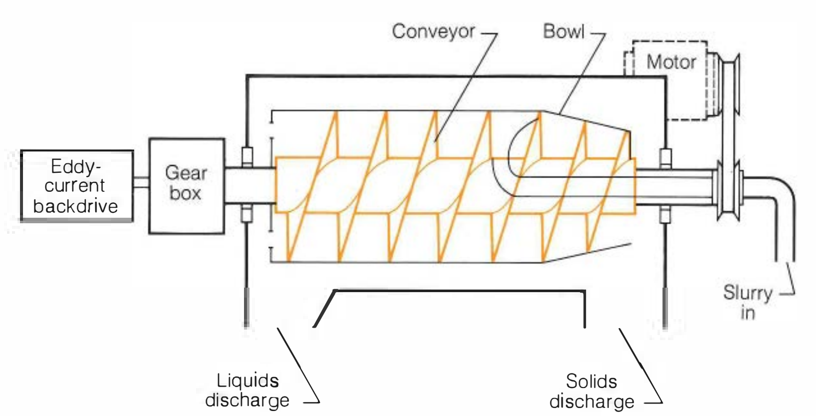


Figure 1 High-g (force) centrifuge, as depicted by Sharples Division of Pennwalt Corp. During operation the conveyor rotates slightly slower than the bowl.

tent. Eventually such tests will be used to predict the performance of the elements that make up coal-cleaning flowsheets and will lead to the development of accurate flowsheet models. Predictive models may improve equipment and flowsheet designs and result in lower costs, improved yield, and higher energy recovery in commercial cleaning plants.

Other development and demonstration work at CCTF is improving laboratory coal-screening procedures. Accurate size distribution data are fundamental to the design of modern coal-cleaning plants because such information dictates the size of equipment, the number of required circuits, and the overall process conditions. The common laboratory procedure used to determine size consist for coal is to screen air-dried coal over several preselected sieves. Several previous studies have shown that dry screening is not always accurate for fine size separations below 28 mesh. CCTF experience with low-rank coals and high-clay coals led to the observation that the dry-screening method for coarse coal may also be inaccurate in some cases.

To define the limitations of present laboratory dry-screening techniques and to quantify and qualify the differences between wet and dry screening, CCTF initiated a project to compare wet- and dry-screening methods on five coals: Kittanning C-split (West Virginia), Kentucky No. 9 seam (Kentucky), Lower Freeport seam (Pennsylvania), Pittsburgh seam (Ohio), and Lower and Middle Kittanning seams (Pennsylvania). Each coal will be dry-screened at seven sizes and its weight percent recorded. The dry fractions will then be individually wet-screened at all sizes less than their top size and the weight percent recorded. Ash content will be determined on all wet-screened fractions and the results evaluated. Data from this comparison are expected in mid 1985.

Some instrument development and demonstrations are ongoing; others are specific tests scheduled and conducted as part of the test plan. These tests are separate from the routine calibrations and verifications of CCTF equipment. During 1984 CCTF compared a slurry mass flowmeter with a standard slurry density gage and a volumetric flowmeter to determine accurate mass flow rates. In addition, CCTF is demonstrating the use of in-line differential-pressure transmitters on pressurized pipes to measure the density of coal-magnetite-water slurries. These transmitters would replace nuclear density gages, which are sensitive to changes in the magnetite-to-coal ratio. The CCTF experience with state-of-the-art instrumentation and computers combined with new instrumentation applications will result in better process control and improved efficiency of coal-cleaning plants.

The CCTF Coal Quality Data Base contains information on coal cleanability characterizations and development and demonstration projects. The data base, currently in hard-copy form, is available to interested utilities, universities, and other research organizations. In the future the data base will be computerized and used to compare the following.

- Raw-coal characteristics, impurity liberation, and cleaning potential of various coals
- Flue gas emission potential
- Equipment performance

The data base will also be valuable in developing computer models; designing alternative handling, cleaning, and combustion techniques; and reviewing the implications of proposed regulations.

Concurrent innovations

To obtain accurate and precise data, the CCTF staff must frequently modify equipment and procedures. These modifications, which are coincidental to the facility's test plan, produce innovations beneficial to utilities in a number of areas, including coal sampling, gravity fractionation, and adiabatic calorimeters.

With 54 automatic coal samplers, CCTF has excellent facilities to demonstrate and improve sampling technology. A computerized bias test data-reduction program developed by CCTF engineers has been used for more than 30 bias tests of CCTF samplers. Several utilities are currently using this CCTF software to evaluate their coal samplers, and this statistical evaluation method is saving time and eliminating human error that can occur in manually reducing data. Further, it identifies questionable data and quantifies the expected bias at several confidence levels.

The results of CCTF tests indicated unacceptable bias levels in many of the samplers tested. CCTF staff selected a worst-case slurry sampler for detailed examination to determine if its bias could be reduced to an acceptable level and if the sampler's reliability could be improved. The staff believed the sampler characteristics that were generating bias were cutter shape, speed, acceleration, and deceleration; nonuniform slurry flow; and splashing. They made a series of mechanical changes to remove these bias generators and improve sampler reliability (Figure 2).

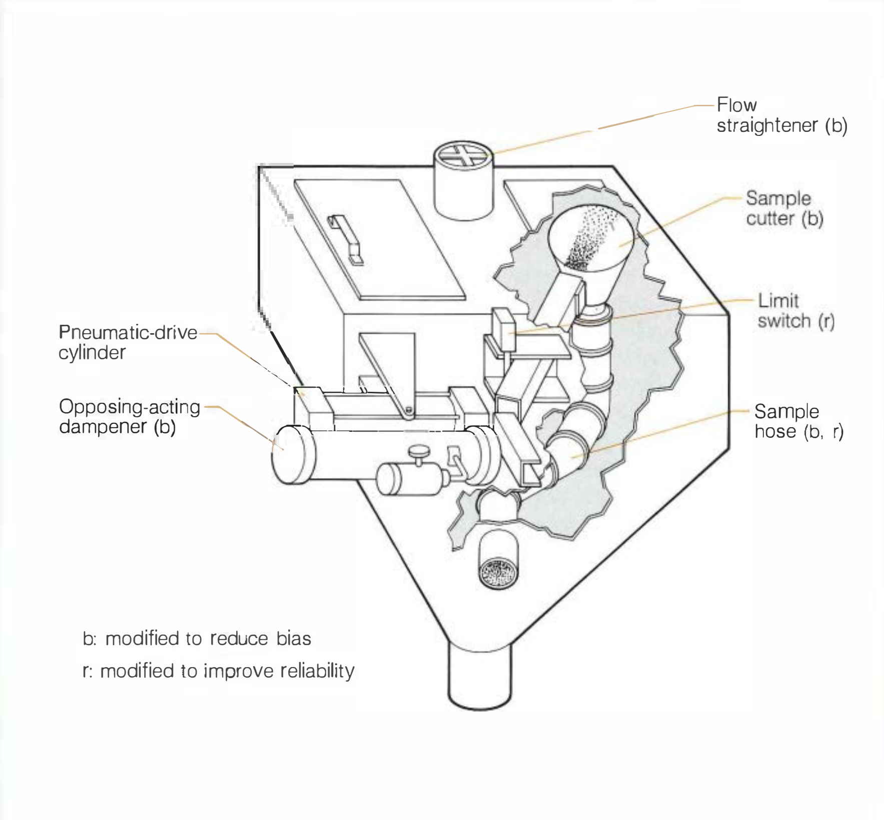


Figure 2 Gravity-flow slurry sampler. Engineers at CCTF modified the sampler to reduce bias and improve reliability.

Gravity fractionation is a laboratory procedure for measuring mineral distribution in different specific gravity fractions of pulverized coal; it attempts to simulate coal firing in a power plant. It helps quantify impurity liberation and may more accurately predict the potential for coal ash slagging and fouling in a utility boiler.

Staff at the Homer City Coal Laboratory (HCCL), which is under contract to analyze CCTF coal samples, have implemented detailed gravity fractionation test procedures. Others developed the process, but a standardized test procedure has not been generally adopted. To rectify this, CCTF and HCCL have developed and implemented a detailed test procedure on several coals. They are reviewing the results to verify the procedure and assess the usefulness of gravity fractionation data in coal cleanability characterizations.

The procedure and results are being presented to boiler manufacturers, consultants, and others interested in gravity fractionation in a series of meetings that should help promote a standardized procedure and effective use of CCTF results.

Laboratory technicians determine the heating value (Btu content) of a coal sample by means of an oxygen bomb calorimeter encased in an insulating water jacket. Although these adiabatic calorimeter systems make few experimental errors, their results can be biased by undetected equipment failures. HCCL has developed several troubleshooting tools (control charts, quality control logs, and maintenance logs) that detect and resolve common problems before such problems upset a system. An HCCL supervisor described these tools and their use at the International Coal Testing Conference. Utilities and others can use this information to ensure accurate analyses and reduce laboratory costs by eliminating unnecessary restandardizations and by reducing equipment downtime.

Technology transfer

CCTF *Campaign Reports*, *Updates*, and technical papers report CCTF test program results and progress in concurrent innovations. *Campaign Reports* are available from EPRI (Technical Information Services), and *Updates* and technical papers are available from CCTF.

By donating coals for testing and by working closely with the CCTF staff during testing, member utilities gain a deeper understanding of state-of-the-art coal-cleaning technology, and they obtain detailed analyses of their coals for future planning and decision making. A successful CCTF test program is not only of significant and immediate value in solving a particular utility's problem or verifying a specific cleaning plant design, but it can also be beneficial in the longer term by adding to the Coal Quality Data Base, which is beneficial to all EPRI members.

Looking ahead

In 1985 CCTF will be adding to its capabilities to accommodate a Department of Energy demonstration of advanced physical coal-cleaning processes. Projects in clean-coal dewatering, coal weighing, and sulfur removal by froth flotation represent the balance of the proposed 1985 test plan, in addition to eight more coal cleanability characterizations. *Project Managers: Clark Harrison and James Hervol*

POWER PLANT COOLING

This status report reviews heat rejection research in progress or planned by the Heat, Waste, and Water Management Program. The projects include each of the principal types of cooling systems for steam-electric power generation: evaporative cooling towers, water-conserving systems, once-through cooling, and cooling ponds and lakes.

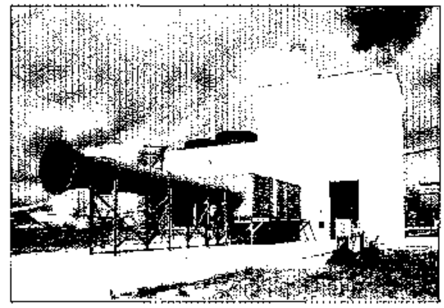
Evaporative cooling towers

More than 80% of the steam-electric power plants now under construction will use evaporative cooling towers. As a result, much of the heat rejection R&D centers on closed-cycle wet cooling. Its main focus is the prediction, testing, and improvement of the thermal performance of evaporative cooling towers. A second research area, of environmental importance, is the prediction and measurement of the tower effluent's spatial distribution, principally the visible plume and cooling-tower drift.

Improving the thermal performance of wet-cooling towers reduces turbine exhaust pressure and substantially improves plant efficiency and economics. In RP2113 a well-instrumented pilot-scale test facility was constructed to assess the thermal and hydraulic performance of a variety of cooling-tower packings. (The packing, or fill, is the material within the tower that promotes evaporation and thus heat rejection.) Construction of the facility was completed in July 1984 (Figure 3). Shakedown tests and facility calibration are complete, and fill performance tests began in January. The 1.5-MW (th) facility, located at Houston Lighting & Power Co.'s W. A. Parish plant, can test all fill types in either a cross-flow or counter-flow configuration. To help select fills for testing at the facility, EPRI screened a limited number of fills in mid 1984 at the Thermatec facility in Santa Rosa, California (RP1260-48).

Related full-scale tests were begun in a dedicated counter-flow cell at HL&P's Clark plant last fall. These full-scale counter-flow tests, together with full-scale cross-flow tests planned for 1985 at the Parish plant, will provide data needed to validate performance prediction methods being developed in this effort.

Figure 3 Thermal and hydraulic performance tests are in progress at this 1.5-MW (th) facility, located at Houston Lighting & Power Co.'s W. A. Parish plant.



These performance prediction methods include three computer codes: VERA2D-84, developed by CHAM of North America, Inc. (RP1262-1); TEFERI, developed by Electricité de France; and FACTS, developed by the Tennessee Valley Authority's (TVA) Norris Engineering Laboratory. In a related effort, Robert D. Mitchell, an independent consultant, is evaluating the VERA2D-84 model for its accuracy and input data sensitivity (RP1260-46). EPRI and a utility consortium—HL&P; Indianapolis Power & Light Co.; Pacific Gas and Electric Co. (PG&E); Public Service Co. of Oklahoma; Southern California Edison Co.; Southern Company Services, Inc.; and TVA—are funding this research. The consortium is seeking additional utility participants. Current plans call for expanding the test program, as well as studying such topics as icing, fill degradation, fan performance, wind effects, measurement of air flow rate, and measurement of water flow rate in large-diameter pipes.

Contractors in the project, responsible for design, construction, operations, testing, and data analysis and interpretation, include Battelle, Pacific Northwest Laboratories, Environmental Systems Corp., and TVA's Norris Engineering Laboratory. In addition, John F. Kennedy Consultants, Inc., is independently reviewing the objectives and scope of this multifaceted project (RP1260-47).

Studies on the environmental effects of evaporative cooling towers focus on the visible plume (a source of shadowing, icing, and fogging) and saline drift droplet deposition (a source of corrosion and potential harm to vegetation). Argonne National Laboratory, the University of Illinois, and the University of Chicago have developed a computer code capable of predicting both trajectories of visible plumes and patterns of saline drift deposition from single and multiple towers (RP906). Project reports describe the model and its validation (CS-1683, five volumes, and CS-1683-SY); a user's manual is also available (CS-3403-CCM). A follow-on effort to assist users, document user experience, and update the model as required is in progress.

Water-conserving systems

EPRI is also sponsoring research to identify, assess, and demonstrate dry and dry-wet cooling technologies that offer substantial economic benefits over commercial systems for utilities that must use water-conserving systems. The principal effort is a demonstration of an ammonia phase-change heat rejection system: the 17-MW (th) Advanced Concepts Test (ACT) facility at PG&E's Kern station in Bakersfield, California (RP422). EPRI and another consortium—PG&E, Southern California Edison Co., Los Angeles Dept. of Water & Power, and the Salt River Project—are sponsoring the project. Battelle, Pacific Northwest Laboratories is operating and testing the facility, with assistance from Union Carbide Corp.

Battelle has tested two air-cooled heat exchangers augmented by water during peak load, as well as a steam condenser–ammonia reboiler with enhanced heat transfer surfaces. Both the Curtiss-Wright Corp. (dry, with a separate evaporative cooler) and the Trane (water-deluged) air-cooled heat exchangers perform as predicted. The steam condenser–ammonia reboiler did not meet original performance estimates, but the impact of lower performance on overall system economics, a 5% increase in total costs, was not significant.

In addition, a capacitive cooling system for peak shaving that operates without water augmentation is being tested at the ACT facility. Testing of the capacitive system, designed and built by Chicago Bridge & Iron Co., began in July 1984. The system performed as predicted. Limited dispatch of the host station and a variety of mechanical problems in the ACT facility have delayed the test program, but test results suggest commercial feasibility. (An ammonia phase-change cycle of 5 MW [e] capacity was put into commercial operation in 1983 near Calgary, Canada.) EPRI has also been exchanging information on this technology with Electricité de France, which will begin demonstrating a 20-MW (e) steam-ammonia bottoming cycle near Paris this year. Construction of the bottoming cycle, described in CS-3254-SR, is nearly complete, and EDF is preparing to load the ammonia charge.

In other work on water-conserving cooling, Dynatech R/D Co. has assessed the potential use of nonmetallic materials in corrosion-resistant, low-cost, air-cooled heat exchangers for dry-cooling or plume abatement applications (RP1260-29). In Europe, utilities and other commercial concerns are already using smooth-tube plastic heat exchangers successfully.

Dynatech has developed enhanced tube configurations, such as low-profile fins, that may offer better performance and lower cost than smooth-tube exchangers (CS-3454). Dynatech plans to verify the predicted performance of these configurations in laboratory tests. EPRI plans to discuss demonstration of a plastic heat exchanger in a plume abatement or dry-cooling application with utilities and manufacturers.

Once-through cooling

A primary concern in once-through cooling systems is the entrainment and impingement of fish at the cooling-water intake. To minimize adverse environmental effects, federal regulations require that intake systems be equipped with the best available technology (BAT). Since 1982 EPRI and an ad hoc committee of interested utilities have been organizing research on cooling-water intake systems. As a result, EPRI has undertaken three projects.

The first project is developing a computerized data base of engineering, biologic, and operation and maintenance information for intake systems at approximately 300 power plants (RP2214-1). Data compilation and verification for the Intake Structure Data Base (ISDB) began in 1982 and will continue through 1985. A statistical analysis of the final ISDB will be completed this year, and the data base will be available on magnetic tapes for mainframe computers and on diskettes for microcomputers. The ISDB should be a very useful information resource for utilities preparing for power plant permit reviews and modifications.

The second research project thoroughly reviewed and assessed intake structure designs to identify proven and promising applications (RP2214-2). The results of this evaluation, summarized in a recent report (CS-3644), indicate that combinations of behavioral barriers may perform as well but at a lower cost than physical barriers, which have been accepted as the BAT standard. For power plant permit renewals, acceptance and use of behavioral barriers could mean a substantial savings.

The third project has produced a manual describing available intake structure test facilities (RP2214-3). Fact sheets summarize important characteristics of each test facility, such as intake technology, source water, and aquatic species. This manual will help EPRI select potential field test sites and provide utilities with additional field performance data on specific intake structures.

Based on recommendations from RP2214-2, future research will focus on developing field performance data for behavioral barrier combinations. Field testing of these barriers at four sites is planned for 1985–1988. Three types of behavioral barriers (bubble curtain, pneumatic poppers, and strobe lights) will be tested at each site. The four sites will be representative of different water bodies (lake, river, estuary, and marine) and their associated fish species. Ontario Hydro's Pickering Generating Station has been selected as the first site. EPRI, Central Hudson Gas & Electric Corp., Ontario Hydro Research, and Southern California Edison Co. are funding these field tests. The consortium is seeking other participants.

Figure 4 Researchers observe the hot (70°C) discharge from the cooling system during preparation for testing at the Savannah River plant.

Cooling ponds and lakes

Current EPRI research on cooling ponds and lakes aims to improve hydrothermal performance through a better understanding of evaporation and through better geometric design (RP2385). Using a variety of techniques, Massachusetts Institute of Technology and a team of other investigators measured evaporation from a small experimental pond of 2-MW (th) heat duty . Data from this and other field studies indicate that existing formulas are adequate to correlate evaporation rate data when appropriate mathematical models are used in analysis and interpretation of field test data (CS-2325). During the fall of 1984 researchers conducted field tests aimed at extending the applicability of existing evaporation rate formulas, in hot (up to 70°C) ponds of unique, simple geometry at DOE's Savannah River plant in Aiken, Georgia (Figure 4). In addition, MIT is conducting laboratory-scale experiments and corresponding mathematical studies of improved discharge and intake designs. These studies are expected to help decrease construction and operating costs as well as increase pond siting flexibility. *Subprogram Manager: John A. Bartz; Project Manager: Wayne C. Micheletti*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

POWER SYSTEM PLANNING AND OPERATIONS

Fast voltage estimation

Unlike the calculation of power system thermal limits, which are linear in nature, calculation of voltage limits is not as amenable to computer processing and therefore rapid calculation. Hence, the objective of this project is to provide utility operators and planners with improved computer tools for quickly calculating voltages that may be degraded by contingencies, shifts in generation patterns, or power interchanges (RP2148).

The project goal is to develop and test a method that will estimate the voltages for a group of contingencies (1) in one-tenth the time of the fastest method now available (fast-decoupled power) and (2) within 2% error as measured against a power flow result. After examining many innovative approaches, a group of methods was chosen that will achieve these objectives when working together in a chainlike fashion. The sequence first examines each scenario posed and sifts out those that definitely do not violate any limits. Next, a linear voltage calculation method called adjoint network sensitivity is used to determine voltage changes at all buses for each remaining contingency. If the contingency is so severe that it is beyond the calculating ability of the adjoint network method, a fast-decoupled or coupled load flow is used.

Results thus far on a small, 39-bus test system show that an 8.5-fold speed-up has been achieved within the specified error limits. Further tests are under way to gauge performance on a 500-bus test network. Conceptual questions, such as how to decide a scenario is beyond the calculation ability of the adjoint network method, must be answered.

Availability of software for utility testing and adaptation is planned for late 1985. Extensions to the method to more accurately incorporate VAR limits and HVDC in the adjoint sensitivity method may be added if utility experience with the method justifies this work. Incorporation of these results into other EPRI software is also contemplated. Systems Engineering for Power, Inc., and Carlsen and Fink Associates are the contractors. *Project Manager: J. V. Mitsche*

UNDERGROUND TRANSMISSION

Watersaw* abrasive water-jet cutting system

Excavation is one aspect of underground cable installation that is labor intensive, and the water-jet technology offers a method for cutting pavement that is cleaner, faster, quieter, and more economical than conventional techniques. The objective of this project was to design, fabricate, and test a prototype water-jet-equipped vehicle that is mobile, self-contained, and operable in city streets (RP7860-3).

Historically, water-jet cutting devices have operated at very high pressure, with no additives or abrasives in the water. This research effort resulted in an abrasive-water mixture operated with relatively simple, lightweight equipment.

The EPRI Watersaw, developed by Fluidyne Corp., is a versatile cutting system designed to meet the needs of the utility industry. Watersaw will be manufactured and marketed as a complete concrete-cutting package for the utility industry. The major components of this total system are readily available from several U.S. suppliers. Whenever possible, proven construction equipment and machine parts were used to give improved field serviceability and reliability. Also, because commercial equipment composed approximately 90% of the total cutting package, system cost was drastically less than for R&D-generated, fully prototyped systems.

Watersaw operates at a water pressure between 10,000 and 20,000 psi (69 and 138 MPa), using red garnet or silica sand abrasive to enhance cutting. The pressure and flow rate determine the required horsepower from the diesel drive motor (Figure 1), and flow rate is a function of engine rpm and nozzle orifice size. The maximum horsepower of the trailer-mounted diesel engine (Figure 2) is 120 hp (89.5 kW), and the maximum pressure out of

*Watersaw is an EPRI trademark.

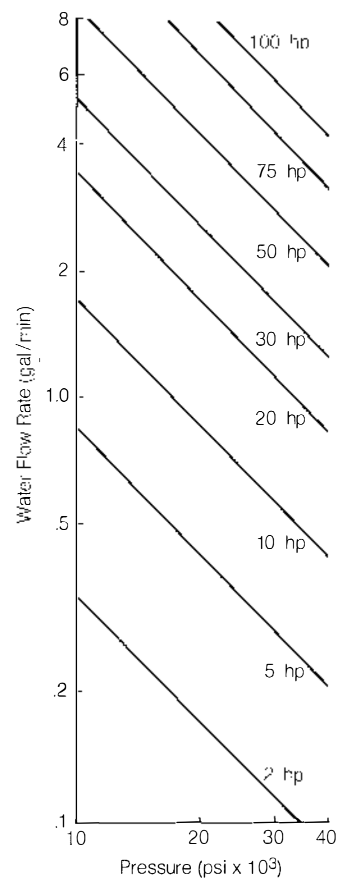
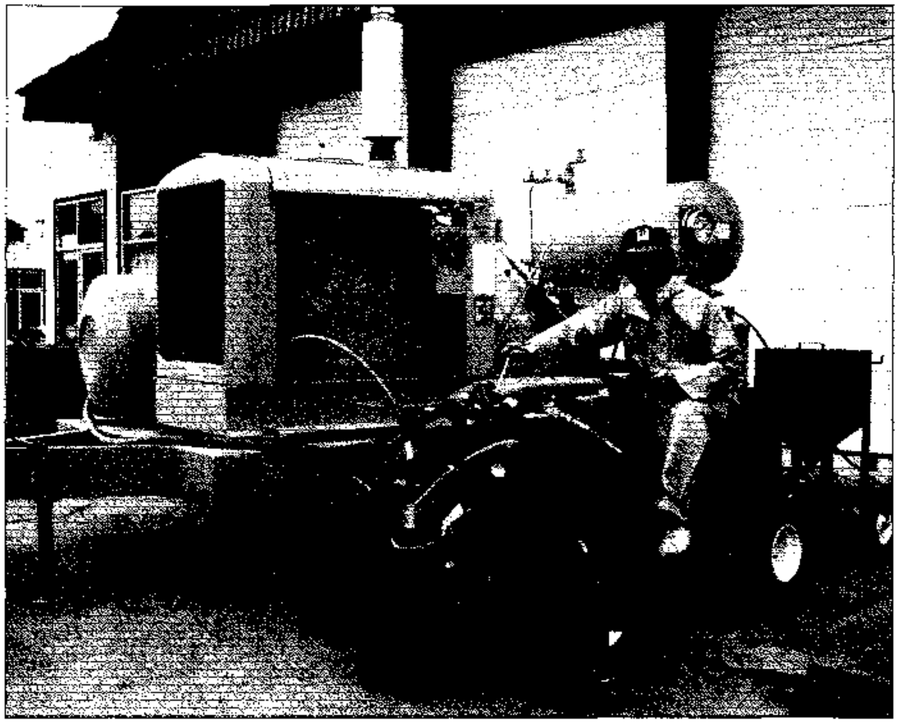


Figure 1 The relationship of horsepower to flow rate and pressure. The circles indicate certain operating points for the Watersaw.

Figure 2 The trailer-mounted power package in the rear supplies the high-pressure water and comprises a diesel engine (left), triplex pressure pump (center), and a water tank/filter system (right). The water is carried to the nozzles by means of the high-pressure flexible hoses seen in front. At front right a shroud covers the high-pressure nozzles. The canister at the rear of the tractor is the abrasive supply tank. The front end is the hydraulic cutting assembly with the nozzles inside the square black box.



the pump is 20,000 psi (138 MPa). This power package is commercially available from construction equipment manufacturers. The cutting nozzles, abrasive tank, and hydraulic positioning assembly are mounted on a garden tractor for mobility and ease of operation when cutting long lengths of roadway. These fixtures can be mounted on any tractor having a low-speed hydraulic drive system.

Cutting rate and efficiency, of course, depend on concrete strength, as well as on system operating parameters. Water pressure, hydraulic horsepower, water flow and abrasive flow rates, distance from the surface (standoff), and traverse rate are all factors affecting cutting depth. The Watersaw accepts up to three nozzles at the present time, each nozzle producing six jets that converge to a point for greater abrasive entrainment and effectiveness. The amount of water and abrasive used varies with the amount of horsepower; however, in most cases when a single nozzle is used, 4.5 gal (17 L) and 1.5–3.5 lb (0.68–1.6 kg) per minute are good starting parameters.

Performance to date has been very encouraging. At 16,000 psi (110 MPa), 3.5 lb/min (0.026 kg/s) of abrasive, and 4.5 gal/min (0.284 L/s) of water, high-strength concrete—6000 psi (41 MPa) compressive strength—has been cut to a depth of 6 in (15 cm) in a single pass. The equivalent traverse rate is 15 in/min (38 cm/min) and the cut width, approximately ⅜ in (0.9 cm).

The Watersaw has many useful attachments for doing other highway jobs. One such device is a rotating manifold containing two or more nozzles for removing (scarifying) road surfaces where weakened or damaged concrete exists. Another device is a handheld cutter for sidewalk cutting and/or vertical walls.

During the last quarter of 1984 this equipment was field-tested to get a realistic view of its performance. Utility demonstrations should commence by mid 1985. *Project Manager: Thomas Rodenbaugh*

OVERHEAD TRANSMISSION

Wind-induced conductor vibration

When aeolian vibrations cause minimal damage (from one to four strand breaks) to overhead transmission lines, utility engineers must decide what action to take. Phases 1 and 2 of RP1278 addressed this issue and found that adding vibration dampers to such minimally damaged lines arrests further deterioration and allows the lines to achieve their full design life. These results were quantified both analytically and experimentally and the results were reported in EL-1946 and EL-3297. Also included in these reports are guideline curves (dynamic bending stress versus number of cycles of vibration), which can be used in the aeolian fatigue design of overhead transmission lines.

Phase 3, which is just concluding, accomplished the following.

- Experimentally evaluated the effect of static bending and suspension clamp radius
- Experimentally verified fatigue predictions for a common conductor size (4.03 cm^2–795 kcmil–26/7 Drake ACSR)
- Experimentally evaluated and defined the range of validity of Miner's cumulative damage hypothesis in predicting ACSR strand fatigue life
- Developed a probabilistic aeolian fatigue design model for ACSR designs

Phase 3 results are expected to be published by mid 1985.

Phase 4, which is just beginning, will build on the previous work to quantify the major design parameters affecting aeolian vibration. Modification factors to quantify the effect of various terrain, windspeed, line conditions, conductor types, line sag angles, line tension, and suspension hardware (armor rods) will be evaluated. The modification factors, in conjunction with the base curves developed in phases 1–3, will allow the transmission line designer to generate design curves that are appropriate for a given line in a given setting. The design curves can then be used with the probabilistic design methods identified in phase 3 to accomplish aeolian fatigue design of overhead lines in a more rigorous and cost-effective manner than has been possible to date. Phase 4 is expected to be completed in the fourth quarter of 1986. *Project Manager: Joseph W. Porter*

Transmission line design wind speed

Transmission lines must be designed to withstand a number of mechanical loading conditions. Wind on both towers and conductors causes some of the more significant loads. Determining the design wind speed is an important aspect of the transmission line design engineer's work.

Typically, the design wind speed is specified as a 50-year or 100-year mean recurrence interval (mri) wind. The design wind speed can be determined either exclusively from data or from a probabilistic model of wind speed applied to some set of data. Analysis based exclusively on data is generally not practical because of excessively large data requirements. For example, data are required for a period about 10 times the length of the recurrence interval—that is, a 500-year period of record is needed to determine a 50-year mri wind.

Shorter periods of record are needed when probabilistic models are used. For example, accurate design wind speed estimates are now commonly obtained from a 20–30-year period of record by fitting the annual maxima to an extreme value type I distribution (so called by statisticians). This project shows that the period of record needed for these estimates can be reduced to 3–5 years by using monthly maxima fitted to an extreme value type I distribution.

Records from 42 weather stations across the United States were used to verify this method for extreme wind speed prediction. The data from these weather stations were evaluated by comparing the 50-year mri wind obtained in a conventional manner with that obtained by using 3-year samples by the new method.

It has been demonstrated that for areas not subject to hurricane-type extreme winds the proposed prediction method can be used for reliable design wind speed estimation. In fact, the 50-year mri wind speed predicted by the proposed method has an average error of less than 1% when compared with the "true" design wind speed determined by the conventional method.

Application of this estimation method will provide transmission line design engineers with more line-loading information from less data than was previously deemed necessary. *Project Manager: Vito J. Longo*

Polysil developments

One of the most promising applications for Polysil material is to develop transmission line or substation structures that do not require added insulators (because Polysil is itself an excellent insulating material). We know that Polysil is, in general, stronger mechanically than portland cement and electrically equivalent to porcelain. The challenge remains to devise a structure that will combine these features yet compete in price with conventional structures, including the added insulators.

Any Polysil licensees or EPRI member utilities who wish to apply their ideas to new designs by using this material may obtain a limited-distribution final report from the EPRI project manager in the spring of 1985. This report resulted from RP2015, which was cosponsored by Florida Power & Light Co. It will describe the electrical and mechanical strength of Polysil members fabricated in representative sizes typically found in structures. Included will be contaminated flashover tests, puncture tests, and tests on nonconductive reinforcement in Polysil beams. The report will contain documentation of the design of one concept consisting of a single-shaft, 138-kV pole with no insulators. Although this particular design turned out to be more expensive than a conventional pole with added insulators, the concept remains viable for other designs. It is hoped that the knowledge gained in this project and the design data obtained will provide impetus for more cost-competitive designs in the future.

In the first quarter of 1985 the report on the first three years of the Polysil 69-kV insulator field tests (RP1281) will also be available. The objectives of these tests were twofold: to observe how Polysil performs under actual service conditions, and to see how variations in shape, material, coating, and electrical grading affect the performance of the insulators. In general, the performance of the Polysil insulators was as good as or maybe better than that of the standard 69-kV porcelain post insulator installed on each test rack. And the uncoated, ungraded design appears to be the best selection for most service applications. Utilities interested in pursuing the possible cost savings of Polysil insulators may be particularly interested in the details of the field tests contained in this report. *Project Manager: John Dunlap*

Subsynchronous resonance damping scheme

In the November 1982 *EPRI Journal,* a new subsynchronous resonance (SSR) damping scheme, referred to as the NGH–SSR damping scheme, was described (RP1504-3). The scheme consists of a back-to-back thyristor switch in series with a resistor, which is connected in parallel with a series capacitor. With special thyristor firing controls, it is possible to suppress subsynchronous electrical torque on the generator shaft, damp subsynchronous oscillations, reduce stresses on the series capacitor, and protect the series capacitor.

After successful simulation tests, it was decided to build and demonstrate a prototype NGH–SSR device for one series capacitor module on Southern California Edison Co.'s Mojave-Lugo 500-kV line. Significant financial contributions were made by EPRI, SCE, and Siemens, and smaller financial contributions by Arizona Public Service Co., the Los Angeles Dept. of Water & Power, Nevada Power Co., Salt River Project, San Diego Gas & Electric Co., Tucson Electric Power Co., and the Western Area Power Administration. A contract was awarded to Siemens-Allis Corp. to design, manufacture, and deliver a prototype scheme to Lugo for one 9.5-ohm series capacitor segment for installation and testing by SCE. The installation was completed by March 1984.

As shown in Figure 3, the SSR device for

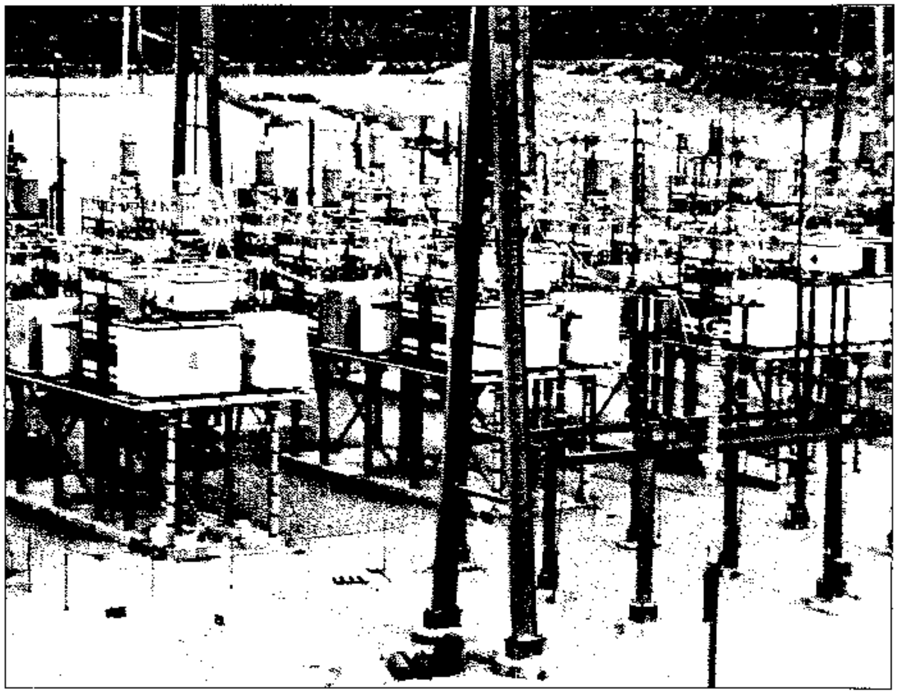


Figure 3 NGH–SSR damping scheme installed at Southern California Edison Co.'s Lugo substation, terminus of the Lugo-Mohave 500-kV transmission line.

each phase consists of three cabinets located at the end of each series capacitor platform. The largest cabinet houses the 60-kV thyristor switch, with 18 thyristors in series for each polarity. An adjacent box contains the 2.65-ohm resistor and a small inductor. The box on top of the thyristor switch houses the current- and voltage-monitoring devices. The control and protection electronics are located at ground level and connected to the platform equipment by fiber optics.

During August and October 1984 a variety of tests were carried out, which consisted of the capacitor insertion, capacitor bypass, line switching, and line short-circuit tests. As predicted by the simulation studies of the test cases, the tests showed that the SSR scheme removed the capacitor's dc bias on insertion, suppressed electrical oscillations at subsynchronous frequencies, reduced voltage stresses on both the SSR and non-SSR capacitor segments during their insertion, reduced the subsynchronous torque and twist of the turbogenerator shaft, and withstood the line short-circuit duties.

The SSR scheme was also tested for protection of the series capacitor by being programmed to fire at a voltage slightly lower than the protective gap sparkover. The SSR scheme fired correctly, thus protecting the capacitor while suppressing the oscillations and eliminating the need for the protective gap to sparkover.

The prototype has now been put into service for field evaluation by SCE. *Project Manager and Department Director: Narain G. Hingorani*

Transmission line optimization

Decisions concerning transmission line design are much more complex today than they were a dozen years ago. Intervenors are having more to say about line routing, appearance, and influence. Scarcity of capital is prompting increased efforts at cost reduction. Energy costs are such that it is now mandatory for designers to factor the cost of electrical losses into their evaluation. However, the larger conductors called for by the loss evaluation also reduce the corona effects (audible noise and radio interference), and corona is no longer a design-limiting factor. Likewise, these same large conductors operate cooler so temperature is probably not limiting. As a result, line design is a new game with new rules and a lot more of them. Designers need much more analytic power at their disposal to cope with both existing and evolving demands.

In RP2151, EPRI's contractor, Power Technologies, Inc., is developing an extremely powerful and easily used computer program called TLOP (transmission line optimization). Version 1.2 of this program was reviewed with industry leaders in 1983, and their input led to version 1.3, which has now been released. Three optimization seminars were held in 1984 for utility engineers. Attendees came from as far away as Spain and Taiwan, and their response was overwhelmingly favorable.

TLOP can be used to compare thousands of combinations of conductor systems, span lengths, right-of-way widths, environmental criteria, loading criteria, cost factors, and performance requirements. Transmission line designers can now easily study these thousands of possibilities and base their decisions on supportive evidence. The final decisions, of course, still fall to the designers and their management. Not every factor influencing line design can be included in a computer program, but at least decision makers will have enough cost data at their command to make informed decisions.

Besides the obvious usefulness of TLOP to the designer, the program is useful to the researcher as well. Many runs of the program are being made to determine sensitivity of costs to various parameters. Such a search reveals areas ripe for future research. Expert designers have known for a long time that higher everyday conductor tensions can reduce line costs if there are not too many angles in the line, but higher everyday tensions bring potential problems with vibration. Now we have the ability to determine how much we stand to save and, consequently, how much we can afford to spend on research to solve the vibration problem.

Individuals and companies often bring ideas to EPRI for improvements in materials or hardware. For example, two organizations have come to EPRI with ideas for improving transmission line conductors. These suggestions have been evaluated and the developers were encouraged to pursue them a little further to better determine their usefulness. Another firm has won a DOE contract to develop a device that will limit the impact stress on a tower caused by a breaking conductor. TLOP will be used to evaluate this development.

It is one thing to study potential cost-saving ideas on a computer, and something else to demonstrate these ideas. As part of RP2151 EPRI plans to schedule full-scale demonstrations to prove as many promising ideas as is practicable. Full-scale tests of the impact-limiting device mentioned above will be conducted on the 2-mi-long research line No. 1 at TLMRF. Research lines 1 and 2 will be used to test many innovative ideas developed by others. The second line will be built almost entirely from contributed components, of which only the conductors are conventional. Many of the structures will be constructed from innovative, cold-formed shapes that have potential for economy. By installing some of these towers we can assess their construction and maintenance costs; we can monitor their vibration behavior; and we can test them for responses to static and dynamic loads. In a sense, we can "kick the tires" before we make a down payment.

Optimization means many things to many people, and in RP2151 we are taking the broadest possible view to spot promising subjects for further research. At the same time we are giving transmission line designers a valuable tool that they can use to solve today's problems. *Project Manager: Richard Kennon*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

PCB RISK MANAGEMENT METHODOLOGY

Managing risks from utility equipment containing polychlorinated biphenyls (PCBs) requires decisions by EPA, local regulators, and utilities. These decisions address what PCB-containing equipment to phase out and over what schedule, what substances to use in the replacement equipment, what procedures to apply in cleaning up spills, and to what extent spills should be cleaned up. The decision-making process must weigh concern about public health, the large investment required to replace existing PCB-containing equipment, the high cost of cleanup, and the potential for utility liability. Reaching consensus is particularly difficult because of the high stakes and a lack of solid information. Analytic tools can help integrate available information and organize it in a way that clarifies options for decision makers. Under RP2595 EPRI is sponsoring work on a PCB risk management methodology to meet the need for such tools.

The goal of RP2595 is to develop methods for evaluating alternatives for PCB risk management. The methods can be used to address decisions at the national level (e.g., an EPA-required phaseout of all PCB transformers in buildings by 1990) and decisions at the individual company level (e.g., an earlier voluntary phaseout of PCB transformers in buildings).

To date, the work has focused on health risk management decisions at the national level. A model known as TRIM (transformer/capacitor risk management) has been developed for cost-benefit analysis of regulatory proposals for dealing with PCB equipment. The TRIM effort was closely coordinated with other PCB-related research by the Energy Analysis and Environment, Coal Combustion Systems, and Electrical Systems divisions. In an early application of the model, the Utility Solid Waste Activities Group (USWAG) used a prototype version in commenting to EPA on the relative costs and benefits of various transformer fire risk management strategies.

TRIM consists of submodels in four areas: PCB equipment, spill and accident incidents, exposure, and health and environmental effects. As shown in Figure 1, these submodels are integrated into a comprehensive analytic tool for evaluating regulatory options. The model's structure enables it to represent decisions affecting the replacement of PCB-containing equipment, the chances of accidental releases, and the amount of human exposure during and after incidents. These decisions influence the number and severity of incidents, the extent of exposure to PCBs and other substances (in terms of both number of people and dose), ecological effects, and the number of potential severe health effects resulting from the human exposures.

The equipment use and replacement submodel provides a detailed inventory of the PCB equipment under consideration at any time, given a particular regulatory environment. The model tracks equipment use in various locations and accounts for the removal of units from service and the installation of different units. It also calculates the costs of phasing out and replacing equipment and of any special risk management activities.

The spill/accident incident submodel specifies the amount of PCB material released during different types of incidents defined by the user; the frequency of occurrence of these incidents; the production of any byproducts, such as polychlorinated dibenzofurans (PCDFs) and polychlorinated dibenzodioxins (PCDDs), during the incidents; and the residual concentration of the material after cleanup.

Given the type and location of a spill or accident, the human exposure and deposition submodel calculates for each user-specified population group the number of people exposed to PCB material and the average lifetime deposition. Exposure is calculated both for the short period during the incident and cleanup and for multiyear periods after cleanup is completed. A parallel submodel determines environmental exposure, including the exposure of other organisms.

The human health effects submodel calculates the occurrence of potential serious health effects due to exposure to PCBs and any byproducts or contaminants for each of the specified population groups. Likewise, the environmental effects submodel estimates the ecological damage stemming from the accidental releases calculated in the incident submodel.

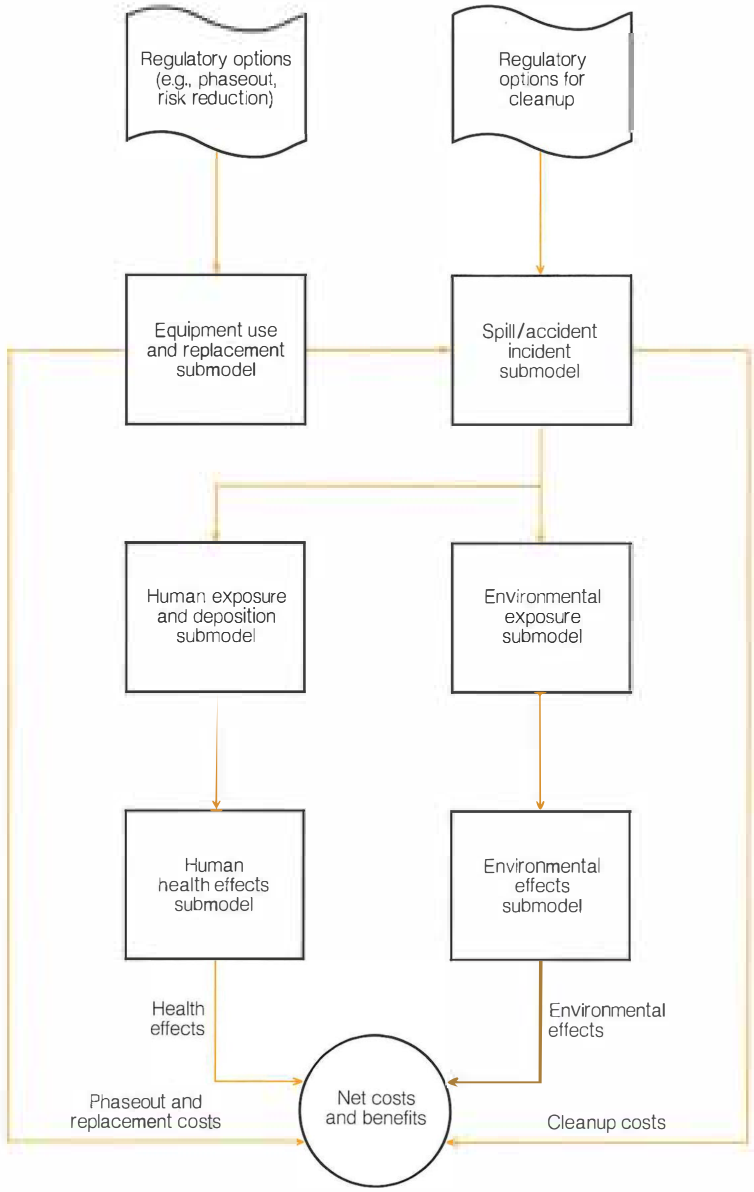
A key point of many decision issues is uncertainty. TRIM can explicitly represent such uncertainties as those governing the rate of spills, the degree of human exposure, and dose-response relationships. The model combines discrete probability distributions with a probability tree structure that expresses the possible outcomes and their likelihood of occurrence.

The initial application of TRIM by USWAG illustrates the model's scope and capabilities. In response to EPA's March 1984 Advanced Notice of Proposed Rulemaking Concerning PCBs, USWAG sponsored an analysis of the following six policy options for controlling the risk from transformer fires.

- Normal equipment-replacement schedule
- Voluntary equipment phaseout
- Accelerated phaseout (by 1995)
- Highly accelerated phaseout (by 1990)
- Risk reduction measures (e.g., outfitting transformers with a device for automatic shutoff in case of fire)
- Risk reduction measures plus a program to notify firefighters in advance about the location of PCB equipment

The USWAG analysis covered one type of equipment (PCB transformers) in three locations (utility substations, buildings with a low exposure risk, and buildings with a high exposure risk) for three types of incidents (small leaks and spills, large incidents without fires, and incidents with fires) and four population groups (office workers, utility workers, emer-

Figure 1 Structure of the TRIM (transformer/capacitor risk management) model for cost-benefit analysis of regulatory options involving PCB equipment. In determining the costs and the health and environmental effects of alternative proposals, the model brings together information from diverse sources.



gency workers, and others).

For each population group, TRIM calculated the total number of potential lifetime health effects in the United States stemming from exposure to PCBs, PCDFs, and PCDDs released through PCB transformer incidents. The model also estimated nationwide costs for equipment phaseout and other risk control measures and for incident cleanup. All results cover the period 1985–2010. The analysis indicated that the alternatives to a voluntary equipment phaseout involve significant additional costs (ranging from $15 million to $822 million) and produce negligible results in terms of reducing total health effects. The TRIM findings were submitted to EPA as part of the industry's comments on the rulemaking notice.

RP2595 initially focused on the development and testing of TRIM for analysis at the national level. Work is now under way to adapt and document TRIM for risk management decisions at the individual utility level. In this form TRIM will help users evaluate the costs and health benefits of voluntary or locally mandated programs to replace PCB-containing equipment on a company basis.

Versions of TRIM have been developed for both mainframe and personal computers that are compatible with the IBM PC. It is important to note that RP2595 is limited to methods development and testing; actual applications are outside the project's scope. To assist users two documents have been prepared—a final report describes the model in detail, along with application procedures, and a user notes document provides information about preparing data sets and running the model. The software and supporting documentation are now available from the EPRI project manager.

In other work under RP2595, researchers will be developing tools that will help utilities manage the risks associated with PCB and PCB-contaminated mineral oil equipment. Also, industry advisers have expressed a strong need for tools to address PCB spill cleanup issues and to evaluate PCB replacement equipment. Plans are being made to develop such tools in this year. *Project Manager: Victor Niemeyer*

TOXICOLOGY OF CHEMICALS IN THE UTILITY WORKPLACE

To provide for effective exposure control, utility managers need information about the chemicals used in the utility workplace—their exposure potential, their fate in the environment, and their potential to cause long-term health effects. Concerns in all types of industries about diseases caused by occupational exposure to chemicals have led to a proliferation of state and municipal chemical labeling and worker right-to-know legislation. These measures require, among other things, disclosure of the chemicals to which workers may be exposed and the possible health consequences of such exposures. As a first step in ensuring that utility managers have the information they need, a project was initiated to assess the literature on chemicals in the utility workplace (RP2222). The assessment focuses on identifying what chemicals are used by utilities and what information is available regarding their toxicity and their potential for causing long-term health effects. The objective is to provide utility health and safety personnel with a readily accessible resource on the potential hazards of chemical exposure.

The first task in this project was to construct a master inventory of chemicals used by utilities. Questionnaires were sent to 94 utilities representing a cross section of the industry in terms of generating capacity, type of power generation, number of employees, and geographical location. The utilities were asked if they maintain a list of the chemicals they use or generate. Of the 94 contacted, 24 were able to provide such a list.

From these lists the project team compiled a master inventory of about 750 individual chemicals and 4500 chemical products in use. The formulations of some 1500 trade name chemicals have been identified from information from the utilities, available data bases, or the manufacturers or vendors. The inventory covers a wide range of chemicals, from complex organics to simple inorganics. Among the substances included are herbicides, pesticides, biocides, wood preservation agents, and chemicals used in treating boiler water.

Next the master inventory was reviewed by a panel of toxicologists, who identified those chemicals not considered to have adverse health effects (such as sodium chloride) and thus not requiring toxicity evaluation. This screening eliminated about 150 chemicals from the list. Project personnel then reviewed the scientific literature to produce a hazard profile for each of the remaining chemicals. The primary sources were computerized data bases (e.g., MEDLARS) and standard reference sources. In collecting this information, the researchers emphasized data on long-term toxicity (e.g., carcinogenicity, mutagenicity, teratogenicity, and reproductive toxicity).

To supplement the information from the survey questionnaire, project personnel visited a number of utilities. They obtained additional information on exposures and work practices and also asked the utilities to estimate the number of employees assigned to each of five job classifications: operation, maintenance, construction, administration, and other.

The next step was to develop a prioritized list based on the following: chemical exposure, physicochemical properties, amounts used, protective measures taken, and the number of workers exposed. Panels of toxicologists and industrial hygienists assigned numerical values to the biologic risks for particular chemical exposures. These values were assigned according to a predetermined scheme. For carcinogenic risk, for example, a high value was given if a chemical is a known carcinogen in animals or humans or tested positive in a battery of laboratory tests. A lower value was assigned when the scientific evidence for carcinogenicity was less compelling. When no scientific data on carcinogenicity were available for a chemical, it was given a high score, especially if it belonged to a class of known or suspected carcinogens.

All chemicals were scored for carcinogenicity, teratogenicity, mutagenicity, reproductive toxicity, and subchronic effects. A similar scoring system was used to calculate an exposure index for each chemical on the basis of such factors as the likelihood and magnitude of potential exposure. This effort produced several lists—lists for carcinogenicity, teratogenicity, and total toxicity, as well as an exposure index—that can be used for a priority ranking of the chemicals.

Some 400 chemicals associated with wide differences in biologic endpoints (e.g., carcinogenicity versus teratogenicity) are now to be ranked so that chemicals with a higher biologic risk can be segregated from those that are less hazardous. About two dozen ranking systems have been developed and used in the past two decades by government agencies, the chemical industry, and others. Although these systems have certain characteristics in common in that they all apply mathematical formulas (or algorithms) to normalize the potential health risks from exposure, there are considerable differences in their requirements.

Selecting a ranking system that meets the needs of electric utilities was the subject of a workshop held in May 1984. Utility representatives and EPRI staff reviewed existing ranking systems and evaluated the one proposed by the contractor for RP2222. The system selected emphasizes three key elements: chronic toxicity, potency of the chemical, and exposure. Each element consists of several factors, each of which is assigned a numerical score. These factors are as follows.

- Toxicity: carcinogenicity, mutagenicity, reproductive toxicity, other chronic health effects
- Potency: concentration, time, carcinogenicity
- Exposure: chemical use, controls, frequency of use, population at risk

Toxicity is derived by adding together the scores for the four listed factors. Each of the first three is assigned a value from 0 (no biologic activity) to 4 (unequivocal activity in humans). The fourth factor, other chronic health effects, is scored from 0 (no effects) to 3 (lethal effects or a high probability of irreversible effects). Weighting factors are applied in the summation to reflect that carcinogenicity and reproductive toxicity are considered more important, and mutagenicity less important, than other chronic health effects.

The potency of a chemical, or its ability to cause adverse effects, is also derived by adding the scores for the listed factors. The concentration (or dose) is the amount, in mg per kg of body weight, required to cause adverse effects; it is scored from 0.1 (more than 500 mg/kg) to 3 (less than 1 mg/kg). The second factor, time, refers to the interval between exposure and the observation of adverse effects (1 = 90 days or more, 3 − 30 days or less). A value of 1 is added if the chemical has been demonstrated to be, or is suspected of being, a carcinogen in animals or humans.

The exposure score is the product of three factors—chemical use, frequency of use, and population at risk—with the chemical use factor weighted for controls. A value of 1 to 10 is assigned for chemical use: 1 = lowest possible exposure (only small amounts being used routinely), 5 = median exposure (e.g., applying herbicides), and 10 = highest exposure (e.g., spray painting). The control factor indicates the extent to which exposure is mitigated (1 = no controls, 2 = highly effective controls with a mitigation of 50% or better). The factor for frequency of use is scored from 1 (one day per year) to 5 (full-time use). The factor for population at risk is the logarithm of the number of potentially exposed workers.

It is clear from the foregoing discussion that ranking systems in general, even though based on the best available technical information and judgment, are relatively crude methods for assigning priorities to large numbers of chemicals. However, past applications—for example, in government toxicity-testing programs—have demonstrated their value and validity. The application of the proposed ranking system to the 400 chemicals listed by the utilities is expected to identify those to which utility management should pay most attention.

Detailed monographs describing toxicity will be developed for the chemicals of greatest priority. Sample monographs are being prepared and will soon be made available to utility participants for comment. In addition, a toxicity profile for each chemical will be incorporated into a computerized information system for utility use. The format will closely resemble that of the Occupational Safety and Health Administration's Material Safety Data Sheets. This system will be linked to a trade name data base so that trade name formulas and toxicity information on individual ingredients can be readily retrieved. The results and products of this project should be available in late 1985. *Project Manager: Walter Weyzen*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

DESIGN AND ANALYSIS OF DISTRICT HEATING SYSTEMS

*In 1983 a methodology for assessing the technical and economic feasibility of district heating systems was developed, and site-specific system designs for three U.S. utilities were evaluated (RP1276-5). This research, which includes an assessment of European district heating technology, was conducted by Burns and Roe, Inc., of New Jersey, and is part of EPRI's ongoing investigation of alternative dual energy use systems (DEUS) and their potential application in the United States (*EPRI Journal*, November 1981, p. 53, and June 1983, pp. 56–57). District heating systems burn substantially less fuel than individual oil- or gas-fired boilers in commercial and residential buildings. As alternatives to heating systems, they offer the potential of lowering fuel consumption and cost and of reducing the levels of waste heat and combustion-related air pollutants released into the atmosphere.*

European district heating

District heating has long been practiced in Europe, particularly in Denmark, Germany, Sweden, and the USSR. To determine the technology's potential effect on U.S. electric utilities, this study began with an assessment of the four critical components of European district heating systems: turbines, piping, consumer connections, and thermal energy storage (RP1276-5).

The most critical component of a district heating system is the turbine. Large amounts of steam are extracted from the turbine and used to heat water that is pumped through the piping network. Large cogeneration turbines with condensing tails are currently used and manufactured in Europe. These turbines are capable of increased electric generation in the summer (when electricity demand peaks) and of satisfying the wintertime heating demand. This type of turbine is considered to be most applicable for U.S. utilities because peak demand for electricity often occurs in summer, when electricity is needed for air conditioning. District heating turbines should also be specially designed to meet variable heating and electricity loads. Maximum combined electric and heat generation efficiency is achieved when the turbine is designed to match heating demand.

European network piping technology includes the following important characteristics: the use of low-temperature hot water systems (220–250°F [104–121°C] in the supply line; 110–160°F [43–71°C] in the return line), minimal trench depths, installation of piping beneath sidewalks, optimization of concrete culvert design, reduction of carbon steel carrier pipe wall thickness, and the use of sinusoidal curve pattern designs and piping prestressing techniques, which reduce the need for expansion devices and loops. Because piping system cost is an important factor in the economic viability of district heating systems, planning of U.S. piping systems would benefit by careful consideration of European design features.

Individual buildings are connected to the district heating network either directly or indirectly. In a direct system, primary water from the power plant flows directly into the building's space heating elements. In an indirect system, each building has a heat exchanger that heats water to be used for space heating. The domestic hot water supply in both types of system may be taken directly from the primary water supply (open variation) or routed through a separate heat exchanger (closed variation). Direct and indirect systems with closed domestic hot water supply are generally used in western Europe.

Because heat and electric loads vary daily and seasonally, thermal energy storage (TES) systems, such as those using large insulated steel tanks for short-term storage of hot water, are often used to optimize district heating design. Long-term storage to compensate for seasonal variation in thermal energy requirements would substantially improve the economics of district heating systems, but long-term TES is generally uneconomic and low-cost approaches are still in the development stage (EM-2864).

Evaluating potential U.S. sites

The viability of a district heating system at a particular U.S. location is influenced by technical, economic, environmental, and institutional (regulatory) considerations. The evaluation methodology developed in this study identifies attributes essential to profitable district heating sites, describes the evaluation of heat load and heat source characteristics, recommends appropriate piping systems, reviews plant operation procedures, points out environmental effects, and outlines the economic factors to be considered in system planning.

The key to economical district heating is the concentration of users in residential, commercial, or industrial districts with a minimum heat load density of 60–90 MW/mi^2 (23.4–35.2 MW/km^2). Significant fuel cost savings are feasible only where coal or refuse-derived fuels are used and distances between the heat source and the heat load are short enough for efficient heat distribution. Gas-fired high-temperature hot water boilers can also be considered for initial, peaking, and backup capacity. The best heat source alternative depends on the size of the district heating load, funds available for system installation, and other concerns specific to the district.

For efficient district heating, peak electric load should occur in the summer, with maximum heating load and reduced electricity demand occurring in the winter. Also, because installation of these systems can be expensive, economic viability is improved by step-by-step development in areas where the heat load is expected to increase. Many urban areas in the northeastern United States meet these two criteria and serve as the best candidates for development of this type of DEUS.

The analysis of heat load characteristics identifies the most suitable site for district heating within the area of investigation. Information necessary for this evaluation includes the system design temperature, peak and annual heat loads for each customer and for the entire system, and the system load duration curve.

The system design temperature is the lowest daily average temperature that has occurred for a span of 3–5 days during the last 15 years. Peak and annual heat loads for each customer are based on historical fuel consumption data and several site-specific parameters, including indoor design temperatures. Customer peak heat loads are based on the heating degree days and adjusted to account for site-specific parameters. The peak load of the system is determined by combining the peak loads of all potential district heating customers. The load duration curve is determined from outdoor temperature statistics for the area.

The most economic heat source for a district heating system is a coal-fired electric generating station that can be modified to provide district heat along with electricity. There are four primary alternatives for the conversion of a single-purpose power plant to cogeneration district heating: direct use of cooling water from an existing condenser; use of low-pressure feedwater heaters; extraction of low-pressure turbine steam; and installation of a new district heating turbine.

Direct use of cooling water from an existing condenser minimizes requirements for costly turbine modifications. However, this alternative provides relatively low-temperature supply water that requires additional heating. Low-pressure feedwater heaters can be removed from the power generation cycle, and district heating water circulated through them instead. This results in some reduction in the temperature of feedwater entering the boiler, and less electricity generated. Steam can be extracted from low-pressure sections of the turbine, routed to heat exchangers that heat district water, and returned to the power generation cycle as condensed steam. This heat source alternative only slightly reduces electric generation potential but requires expensive turbine modifications. Installation of a new district heating turbine in the existing power plant is the most efficient and reliable heat source alternative. However, it is the most expensive and requires a large heating demand to cover the capital investment.

Piping system design alternatives are also considered during the evaluation of potential district heating sites. Construction of the piping system in stages designed to coincide with development of the heat source is usually the most efficient approach. Economics of the system's power plant must also be considered during the analysis. For example, piping sizes are determined by the heat load and the water temperature drop between supply and return lines. A large temperature drop minimizes the necessary flow rate of circulating water, piping size, and pumping power, but high-temperature supply water requires higher steam extraction pressure and reduces plant electric generation. Other factors of concern in the design of an appropriate piping system include corrosion protection, leak detection, maintenance, insulation, pipe routing, and installation.

Plant dispatch is determined by heating demand, electricity demand, and incremental generation costs for each proposed district heating power plant. Because heating demand is directly affected by outdoor temperature, system operation can be expected to vary throughout the year. Summertime loads are likely to represent about 15% of district heating system capacity, while wintertime demand could reach 65% of capacity, or more. A 100% heating load requires maximum steam extraction and brings plant electricity generation to a minimum. As the heating load decreases, less steam is extracted for district heating, and electricity generation increases.

When a district heating system uses existing coal- or refuse-fired power plants to replace heat generated by individual boilers that burn oil or gas, a favorable effect on air quality can usually be predicted. Lowered condenser flow in cogeneration turbines reduces the amount of waste heat rejected into the environment. Additionally, eliminating boilers that supply heat to individual buildings not only lessens waste heat but also reduces the levels of combustion-related air pollutants released into the atmosphere.

Economic evaluation indicates that phased development of district heating systems will distribute capital expenditures over the development period, allowing the system to begin generating revenues to offset expenditures. Beginning development with an inexpensive retrofit designed to supply a high-load-density area near the plant will minimize both initial cash outlay and the time between cash outlay and revenue generation. Economic analysis also includes methods for the determination of district heating rates and calculation of the period in which district heating customers can expect to recover retrofit expenses.

Case studies

Potential district heating systems in Lansing, Michigan; Providence, Rhode Island; and Springfield, Massachusetts, were designed by using the methodology developed in this study. The Lansing system was designed in cooperation with the Lansing Board of Water and Light and was planned for development in five phases over a 10-year period. Two coal-burning power plants located in the downtown area currently produce steam for district heating as well as electricity, although the steam for district heat is not produced by cogeneration. The objectives of the design are to add cogeneration capabilities to the downtown power plants, convert three steam heating districts to hot water, and add two new hot water heating districts.

The proposed design begins with a low-cost modification of the existing steam system at one of the power plants. This involves the addition of a heat exchanger to convert steam to hot water and the distribution of this heat to current steam users in a high-load-density area close to the plant. This initial phase is designed to establish the feasibility and economy of converting a steam system to hot water. Subsequent design phases require further plant modifications to allow steam extraction and the addition of distribution piping. After completion of all five phases, the district heating system rating capacity would be a planned 153.2 MW (th), supplying a total peak thermal demand of 132 MW (th) and reducing electric output by 28.6 MW (e). Annual utility heat sales estimates range from 13,650 MWh (th) after the first phase of implementation to 487,950 MWh (th) after installation of all phases of the system.

Economic analysis of this design indicates that a hot water district heating system will supply heat at a lower cost than individual boilers fired with oil or gas and will also permit expansion of district heating to areas in Lansing that cannot be reached by a steam system. Figure 1 illustrates cost comparisons for the Lansing study.

The city of Springfield, served by Northeast Utilities, has embarked on a revitalization effort designed to attract commerce and residents to its downtown area. Consequently, heat load density in the district is expected to increase. Three potential heat sources that can be located in the downtown area have been used in the system design: natural-gas-fired high-temperature hot water (HTHW) boilers installed in an existing boiler plant, a planned solid-waste energy recovery facility (SWERF), and a coal-fired steam turbine generating system.

The Springfield district heating system is designed for development over a nine-year period. Revenues generated in the initial phases of implementation would provide capital for further development of the system. Initial installation of three HTHW boilers, with piping connections to a portion of the downtown service area, would supply a heating system capacity of 35.16 MW (th). Annual sales are estimated to be 76,490 MWh (th). Additional heat-

Figure 1 Projected consumer heating costs for hot water district heating, compared with costs (at projected oil/gas cost escalation rate) for individual oil- or gas-fired boilers in Lansing, Michigan.

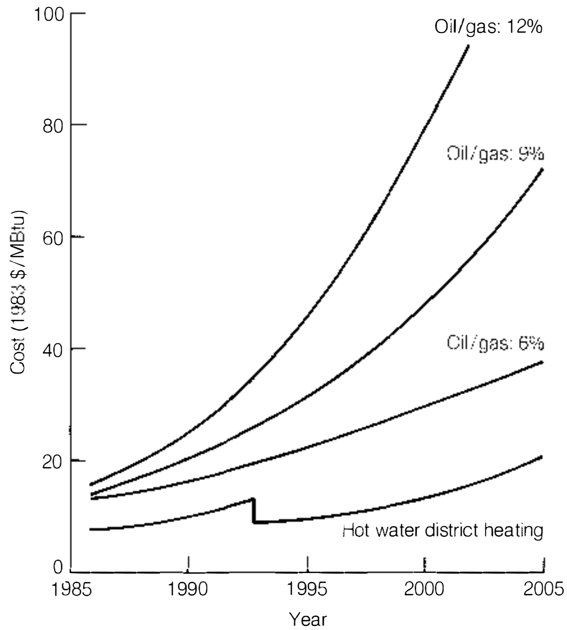
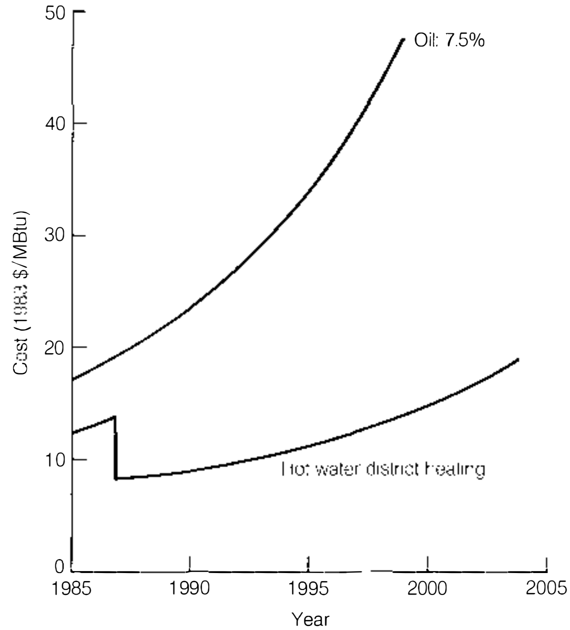


Figure 2 Projected consumer heating costs for hot water district heating, compared with costs (at projected oil cost escalation rate) for individual oil-fired burners in Springfield, Massachusetts.



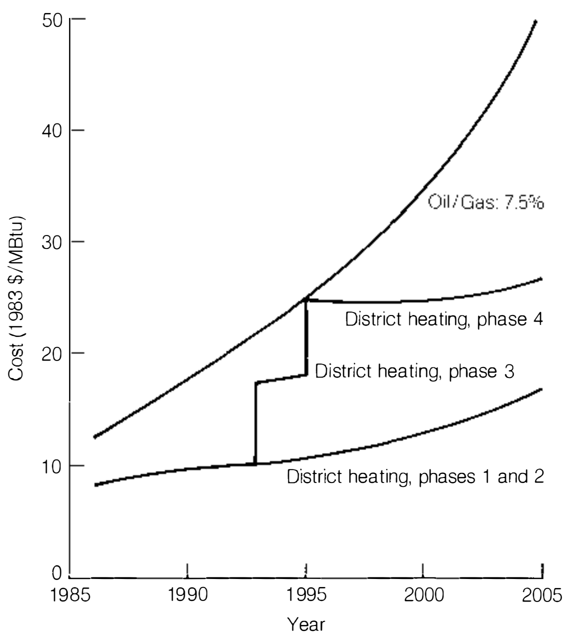


Figure 3 Projected consumer heating costs for hot water district heating, compared with costs (at projected oil/gas cost escalation rate) for individual oil- or gas-fired burners in Providence, Rhode Island. Piping costs for this system design represent 81% of total system cost.

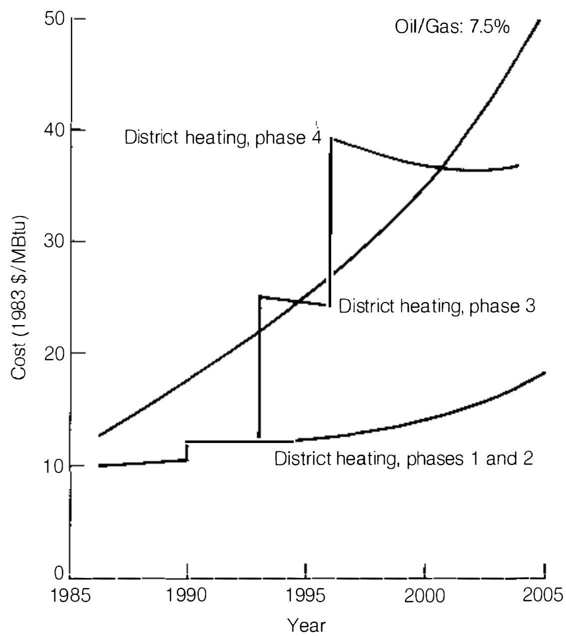


Figure 4 Projected consumer heating costs for hot water district heating, compared with costs for individual oil- or gas-fired burners in Providence, Rhode Island. Piping costs for this system design represent 89% of total system cost.

ing sources, the SWERF and coal-fired steam turbine power plants, would be brought on-line as the district heat load increases. After installation of the entire system, the two power plants would serve as baseload energy sources, and the HTHW boilers would supply backup and peak loads. The complete system would have a maximum heat load of 98.64 MW (th) and total estimated heat sales of 322,157 MWh (th).

As shown in Figure 2, this system will significantly reduce consumer heating costs when compared with costs for individual oil-fired burners. Analysis also indicates that payback of retrofit costs for most consumers will take place in from three to six years.

The Providence district heating system was designed in cooperation with Narragansett Electric Co. In this plan, an oil-fired power plant scheduled for conversion to coal and located in the downtown area is intended as the heat source for five downtown districts.

Development of the system would begin by replacing a second-stage feedwater heater with a district heat exchanger to be used during district heating operation only. This modification would provide a thermal capacity of approximately 15 MW (th) to a portion of district customers, and it would bring the system to a point of revenue production with minimal investment. The remaining three development phases, planned to take place over a nine-year period, involve the addition of a second district heat exchanger, installation of a district heating turbine, and addition of a third district heat exchanger to provide peak capacity. The completed system would have a peak load rating of 102 MW (th) and estimated annual sales of 292,500 MWh (th).

Figures 3 and 4 illustrate heating cost savings (calculated for two cases with different piping costs) resulting from implementation of the Providence design. In both cases, long-term savings for district heating customers are indicated. Results of a consumer retrofit payback analysis show that most prospective customers would recover their conversion costs within three to seven years. Environmental analysis indicates that all three systems will improve local air quality by reducing levels of waste heat and combustion-related air pollutants that are released into the atmosphere.

Implementation of findings

In cooperation with Northeast Utilities, the city of Springfield is using study results to initiate a more detailed analysis of district heating feasibility. It will then decide whether to begin construction. The Lansing Board of Water and Light plans to implement district heating for the downtown area, using the design which resulted from this study. In Providence, the Narragansett Electric Co. was investigating district heating in conjunction with plans to convert the heat source power plant to coal firing. These coal conversion efforts have been suspended because of economic considerations.

District heating has the potential to become a large nationwide industry Systems are currently being implemented, and public awareness of district heating and its benefits is increasing. These systems are being financed and operated by private investors and municipal utilities. Investor-owned electric utilities currently operate the majority of large thermal heat sources that have district heating potential, and they have in place the structure and expertise required to develop district heating as a major industry. However, for utilities to become more involved, economic regulation, taxation, and fuel availability issues must be resolved. *Project Manager: S. David Hu*

FUEL CELL USERS GROUP

Established almost five years ago to help expedite the commercialization of phosphoric acid fuel cells, the Fuel Cell Users Group (FCUG) has grown from 37 charter members to over 60 members today. Recent efforts have focused on the following activities: understanding the applications and benefits of fuel cells for electric utility application; understanding the impact of fuel price and availability on fuel cell use; identifying the engineering and operating issues in early commercial plant designs; and rallying the industry to support initial purchases of prototype and first commercial units. In 1985 at least one manufacturer is expected to announce an offering of market entry fuel cell power plants. These market entry units will have most of the characteristics of the ultimate commercial plants but will cost more. Therefore, one key goal of FCUG is to communicate the results, conclusions, and recommendations of its application studies to those utilities considering the purchase and application of fuel cells on their systems. This will help utilities overcome any cost barriers to these initial purchases. The background of the FCUG and EPRI role in these activities was described in previous EPRI Journal *articles, the most recent in October 1983, p. 55.*

Applications and benefits

In July 1984 EPRI and FCUG jointly issued the *System Planners' Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (EM-3512). This guide was developed by system planners for use by system planners. The guide presents a description of the fuel cell, provides current technical and cost data needed by utility planners to properly evaluate fuel cells (and other modular technologies), suggests various approaches to be used in the evaluation process, and provides examples of benefit calculations. It is intended to help system planners better understand the fuel cell and some of its unique characteristics and to better calculate its associated benefits. FCUG's System Planning Subcommittee advised EPRI in all phases of the endeavor—from selecting the contractor to reviewing the work—and approved the final form of the guide for release to the utility industry.

Some utilities have already performed planning studies that include fuel cells as an option for their systems. Four FCUG utilities presented the results of their studies to the subcommittee, and several more studies are expected to be available in the near future. The common thread in each study was that fuel cells could play an economic role in these utility systems whenever coal plant capital costs exceed $1500/kW (1984 dollars).

None of these studies covered special benefits, such as short lead time, modularity, and dispersed siting. Therefore, FCUG formed a task force to assess the financial and strategic benefits of these fuel cell characteristics. The members of the task force represent all sectors of the utility industry and have expertise in system planning, financial planning, utility financing, and corporate planning. Through case studies of a utility system, this group hopes to better understand and share with the industry how the fuel cell's short construction lead time and modularity might affect a utility's financial and strategic plans for the future. For example, the task force will investigate how the use of fuel cells might affect a utility's interest coverage ratio, external financing requirements, the quality of earnings, and net cash flows, and it will assess the importance of being able to adjust those values by using fuel cells (RP1677-12).

FCUG recently reviewed its 1983 Fuels Report in order to update the original findings (*EPRI Journal*, October 1983, p. 57). Although some of the details have changed, the Fuels and Fuel Processing Subcommittee finds that on the basis of projected availability and price, natural gas remains the most likely fuel cell fuel in the near term. The subcommittee's original conclusion—that dual-fuel capability (natural gas and a liquid fuel, such as naphtha) may allow some utilities to readily take advantage of changing fuel price swings—remains important. Propane continues to show real price stability and may become more attractively priced than other fuel cell fuels in the late 1980s and beyond. However, additional investigation is necessary to determine its use as a utility fuel. Methanol, typically made from natural gas, continues to be priced above all other fuels that are suitable for fuel cell application. FCUG has issued an addendum to its 1983 report covering these points.

To further implement its role in technology transfer, FCUG also presented the fuel cell story to utility chief executives from investor-owned, public, and cooperative utilities at their respective annual meetings in early 1984. This was accomplished through the cooperation of the American Public Power Association, the Edison Electric Institute, and the National Rural Electric Cooperative Association, all of which are represented on the FCUG Board of Directors. Subsequent contacts with many of these chief executives indicated that a significant number of non-FCUG member utilities found the fuel cell of interest and wanted to become more informed about the technology. As a result, FCUG invited representatives from over 200 utilities to one of four regional briefings held in the spring of 1984 with the following objectives.

- Communicate the fuel cell's status and its commercialization challenge to utilities
- Increase utility interest in fuel cell applications
- Encourage utilities to include the fuel cell option in expansion planning studies
- Provide technical or other assistance to any utility requesting it
- Increase the number of potential near-term fuel cell purchasers

Over 50 utilities participated, and five joined FCUG to learn more about fuel cells. But more important, at least nine utilities decided to perform in-house planning studies that would include the fuel cell as an option.

Early power plant issues

FCUG has also formed a utility task force to assess the accomplishments of the 4.5-MW demonstrations in New York City and Tokyo, Japan. This task force will review the technical, siting, regulatory, design, construction, startup, and operation of each unit in order to provide the industry with a utility perspective on what these two demonstrations have accomplished and to suggest issues that it believes remain to be resolved. Although the New York fuel cell was successfully sited amid some opposition by city officials and residents, it has not yet generated electricity ("Fuel Cells for the '90s," *EPRI Journal*, September 1984). However, representatives of Tokyo Electric Power Co. reported to FCUG in March 1984 that its 4.5-MW unit had been generating power since April 1983 and would begin a six-month endurance test program in mid 1984. As both units were supplied by the same manufacturer and are virtually identical (except that improved technology fuel cell stacks are employed in Japan), FCUG believes it is appropriate to combine the results and lessons learned from each activity to properly assess what has been accomplished and what remains to be resolved before proceeding with commercial prototype power plants. The task force's report should be completed in early 1985.

Fuel cell commercialization

Many utilities today are projecting the need for new electric generating capacity in the early to mid 1990s. To meet these dates, conventional central station plants with 8–12-year lead times have to be on the drawing board today. But we know that utilities are not currently committing to new capacity additions; some expect to manage their future loads, while others expect to draw on short lead time technologies as the future draws near and as uncertainty diminishes. The question is, will fuel cells, as an environmentally benign, modular, and short lead time technology, be commercially available to help utilities satisfy their needs in the early 1990s?

FCUG recognizes this question and believes that the manufacturers' current commercialization plans to meet this need can be successful. But this success depends on the support of the utility industry and its creativity in finding ways to overcome the cost barriers that exist. For example, manufacturers plan to offer a few initial commercial prototype power plants soon, but their price will be relatively high because they will be the first of a kind. Subsequently, a limited number of commercial entry units will be offered at a lesser price as mass manufacturing begins, but this price may still represent a cost premium. As the manufacturers continue to drive costs down and see utility confidence in the fuel cell and a continuing market, commercial units will be offered at competitive prices in the early 1990s.

Utilities may be hesitant to purchase these early units because of their cost and a lack of current capacity need. Further, utilities may want to wait until the fully commercial units are available and their own needs are better established. Yet the manufacturers are unable to assume all the risks of building new production facilities to drive costs down until the early units have been purchased and delivered, thereby establishing both the production cost and the utility market. A final complication is that the market introduction phase of the manufacturers' commercialization programs must begin today to meet the expected market need in the early 1990s.

FCUG recognizes this catch-22 situation and is attempting to resolve it in several ways. First, FCUG is continuing to investigate the benefits of fuel cell applications and to share this information with the utility industry. Second, FCUG is sharing the commercialization problem with utility chief executives and senior management to build the high level of support and encouragement needed to overcome this problem. Third, FCUG's regional briefings have encouraged more utility investigations of the role and value of fuel cells in individual utility systems. These studies, combined with utility management's support of fuel cell commercialization, may cause individual utilities to begin to step forward and seriously consider early purchases.

Commercializing these new technologies in today's environment is a major challenge. FCUG has responded well to this challenge, and by working with utilities, DOE, EPRI, and manufacturers, FCUG plays an important role in advancing fuel cell commercialization. Until commercialization is assured, FCUG will continue to be a focal point for utility industry interest in this new advanced technology. *Project Manager: David M. Rigney*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

TRAINING PROGRAM FOR IGSCC SIZING

The through-wall depth of an intergranular stress corrosion crack (IGSCC) in a welded joint of a boiling water reactor (BWR) recirculation piping system is important in fracture mechanics analysis, which determines the effects of such cracks on the structural integrity of the system. Analysis of shallow cracks may show them as having no adverse effects on structural integrity; deep cracks may require the application of weld overlay to preserve the needed margin of safety. The development of ultrasonic inspection techniques for sizing of crack depths and the training of inspectors to apply the techniques successfully have been the focus of a lot of attention in nuclear utility and regulatory circles during the last two years. This report describes some of the background to the inspection problem and illustrates the results of EPRI research on an issue that affects the reliability and availability of nuclear power plants (RP1570-2).

IGSCC of BWR recirculation pipes, even though not a safety issue, has nevertheless been a major factor affecting the availability of BWR plants. When inspectors find a cracked pipe joint, they use fracture mechanics analyses to determine how significant the crack is to system integrity and choose appropriate remedies. These remedies may range from no action to the application of full structural weld overlays to maintain the required margin of safety.

Widespread IGSCC in the recirculation piping of Niagara Mohawk Power Corp.'s Nine Mile Point plant and the concern over the reliability of inspection practices prompted NRC to issue IE Bulletin 82-03 in October 1982, which required BWR operators to demonstrate the effectiveness of their inspection procedures for IGSCC detection. This bulletin was followed by IE Bulletin 83-02 in early 1983, which extended as well as upgraded the earlier requirements. As the concerns over the reliability and the effectiveness of ultrasonic techniques (UT) for the detection of IGSCC began to subside, the long-held concern over the capability of UT to size crack depth began to surface. This concern, expressed by both the utilities and NRC, resulted in the sizing round robin in the spring of 1983.

At its NDE Center in Charlotte, North Carolina, EPRI conducted a round robin to determine the state of practice at the time and to define areas that needed new techniques and/or additional emphasis on the training of inspectors. The results of this round robin surprised the industry. Round robin results, in general, demonstrated inadequate inspector performance and, in particular, showed that practitioners had difficulty distinguishing reliably between deep and shallow cracks and

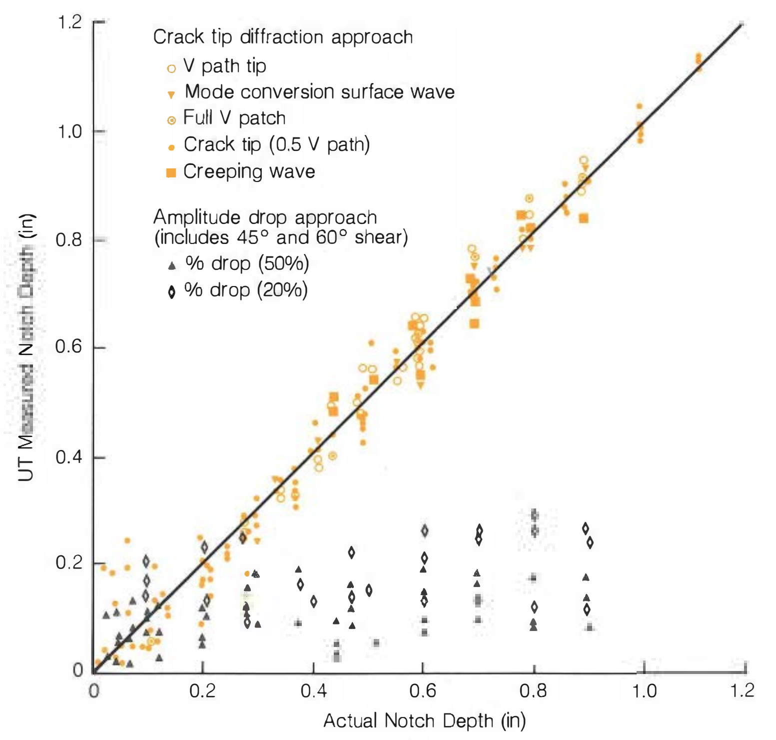


Figure 1 UT sizing demonstration. An international team of experts applied different UT sizing methods. The 45° slope (black) represents the ideal case along which all perfect inspections would fall. The crack tip approach (color) gives accurate estimates. The amplitude drop method (gray) was used by most of the 1983 sizing round robin participants.

that many inspectors seriously underestimated the depth of deep cracks.

In response to the sizing round robin results, EPRI brought to the NDE Center an international team of experts from Japan, Switzerland, and the United States who demonstrated that (1) physically based techniques exist that accurately size cracks and (2) the sizing method used by the majority of U.S. in-service inspectors at the time of the round robin was ineffective regardless of who applied it. This demonstration was comforting, not only because it explained poor performances but also because it showed that performances could be improved.

The international team tested ultrasonic sizing techniques on a collection of machined notches of known depths. The techniques ranged from those that were known to be effective to those that were used by the majority of the round robin participants. Figure 1 shows the experts' data; UT depth estimates obtained by each of two approaches of crack tip diffraction techniques and amplitude drop techniques are plotted against the true notch depth. The solid line with the 45° slope represents the ideal case along which all perfect UT estimates would fall. Note that (1) the poor data points were obtained by the amplitude drop technique, which the majority of the round robin participants used, and (2) the crack tip diffraction method and its variations give accurate sizing estimates.

The experts' findings are the basis of a formal course on crack depth sizing at the NDE Center. Now offered regularly, the course is one week long and consists of lectures, laboratory demonstrations, and exercises followed by a practical six-hour crack-sizing examination. Each student's performance is evaluated by the following criteria.

- Slope of the linear regression line
- Correlation coefficient
- Mean of deviations
- Absence of critical undersizing

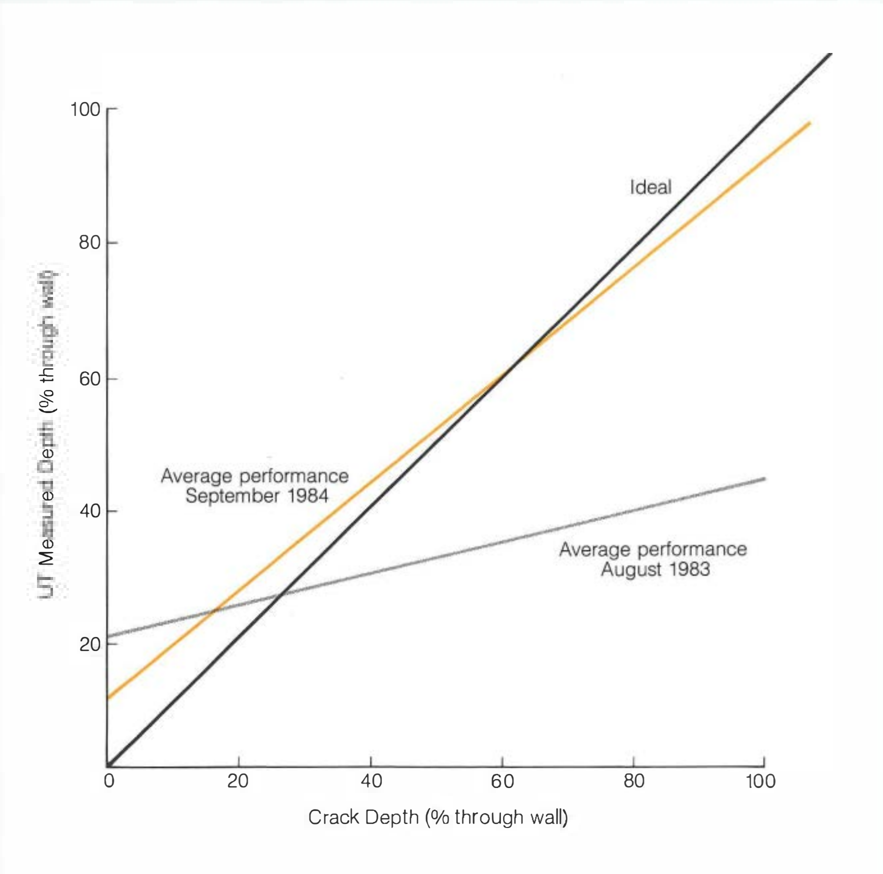


Figure 2 Improvement in IGSCC depth sizing. Linear regression slopes show the average performance of those who are now passing the training course (color) and of those who participated in the 1983 round robin (gray), reflecting the improvement in IGSCC depth sizing. The 45° line (black) represents perfect sizing.

Dramatic improvements in the performances of inspectors who have successfully completed the NDE Center course are best highlighted by comparing them with the performances of round robin participants. Figure 2 compares each group's linear regression line, which represents the average of that group's UT estimates. The 45° line is the ideal performance—perfect sizing. Although a group's performance trend does not guarantee an individual inspector's level of performance, it nevertheless illustrates the tremendous improvement that has been achieved by the industry in just one year.

As a result of EPRI's rapid and effective response in helping the BWR utilities meet NRC demonstration requirements and the establishment of the NDE Center IGSCC training and testing program, EPRI, the BWR Owners Group, and NRC established a coordinated plan governing the training and qualification of NDE personnel. This agreement is an important and unprecedented one among the three parties. It not only endorses the training programs of the NDE Center but also recognizes that successfully passing the center's practical examination is the only adequate means of meeting the NRC's capability demonstration requirements.

Although the coordinated plan was initially drawn to cover the qualification of UT inspectors for IGSCC detection, it has been expanded to include the testing and qualification for UT crack sizing as well. The NRC's endorsement of the sizing course and its examination represents an amazing turn of events. A year ago NRC had no confidence in any inspector's ability to size the through-wall depth of an IGSCC; as of December 1984, more than 45 UT inspectors met the NRC's acceptance standards, and the number has been growing. In general, 35% of those who take the sizing course pass its practical examination. This low percentage results mostly from the rigor of the examination and the inability of many students to unlearn their previous biases in favor of the effective new techniques shown in the course. *Program Managers: M. Behravesh and Gary Dau*

SIMPLIFIED PIPING DESIGN

Nuclear power plants have a vast number of pipes of different sizes and classifications. Class 1 piping is part of the primary pressure boundary; class 2 and class 3 piping comprise various cooling and process systems that carry out general power plant functions. Because of the large number of class 2 and 3 system pipes, especially those of smaller diameter, and the large number of supports they require, designers have developed so-

called simplified piping methods over the years. These methods have generally been tailored for specific projects and are proprietary, so utilities do not have access to the best available simplified methods. To provide utilities with a qualified simplified piping handbook suitable for small-diameter piping (≤4 in), EPRI developed a simplified piping analysis (RP2227). This project was begun in 1982 at the request of the Structural Mechanics Subcommittee, which represents various utilities. The first two phases of this three-phase project have been completed, including the development of a preliminary handbook and the evaluation of several piping systems using the new handbook. One way to make the most of a handbook is to use its contents as input to piping optimization computer programs, such as HANGIT. Phase 3 work, which is now in progress, will produce a theoretical manual, a final version of the handbook, and a verification manual.

Small-piping handbook

EPRI developed the *Small-Piping Handbook* to address explicitly the ASME Code service level B and D design conditions and to consider implicitly the normal and emergency conditions (service levels A and C). These conditions cover the pressure, thermal expansion, and seismic loading of any pipe configuration, including branched piping. The handbook presents a progressive method for locating pipe supports throughout the system. It contains worksheets that can later be assembled as quality assurance records. In addition to locating supports, users can develop support loads with this document.

Designers locate supports by using simplified hand calculations that check for stresses resulting from thermal expansion. The handbook provides alternative methods to lead designers through support modifications that will satisfy the thermal expansion requirements. Next, simple hand calculations and prepared tables, which make possible a complete description of snubber and weight support needs, cover weight and dynamic seismic conditions. The method checks for deflections and prescribes alternative methods for modifying snubber locations if stress requirements are not satisfied.

Of course, using simplified formulas to satisfy weight, thermal expansion, and seismic loading cannot produce as accurate an evaluation as can a computer analysis of the piping system, so the simplified formulas and tables must include some conservative features. The significance of this conservatism is that some designs that do not pass all the handbook requirements may still actually be acceptable if checked by computer analysis. Computer verification suggests that if designers use the handbook as a tool for preliminary support and snubber layout, they can then use a modern piping program to fine tune or optimize the design if necessary. Consumers Power Co. has used the handbook in this way with a computer analysis. Such an approach can significantly reduce the use of seismic snubbers.

Utility verification

To verify the approach, assess its ease of operation, and obtain a second-party review, EPRI contracted with Duke Power Co. and Northeast Utilities to analyze 10 existing small-bore piping systems both by the handbook method and by vigorous computer analysis. Utility personnel carried out the analyses, an essential part of the project, which was initiated as a result of strong utility urging for a simplified process that utility staff members could use. The handbook, which provides piping support loads and locations, was designed to ensure that the requirements of ASME and ANSI codes and standards are met. On the basis of vigorous computer analysis, the utility review verifies that use of the handbook rules satisfies stress requirements.

Many utilities do not have the in-house capabilities for such computer analysis, so they will be interested to learn that this verification produced three conclusions.

- Handbook design is generally conservative, compared with computer analysis.
- Conservatism in seismic supports leads to augmented thermal stresses.
- Seismic support loads are generally excessively conservative.

Project results were presented at a utility workshop cosponsored by Duke Power on June 30, 1983. The workshop was designed to obtain feedback from the nuclear utilities on the use of the simplified analysis methods. Participants had several recommendations and conclusions.

- A companion theoretical manual is needed.
- Skill and quality assurance levels were adequate.
- Local training workshops would be desirable.
- Handbook procedures should be automated.
- Utility use of the handbook method should be evaluated to establish a trial piping design and minimize the number of supports by means of a commercially available support optimization program.

The decision to computerize the method has to be evaluated on the basis of anticipated utility use. More than 40% of utilities attending indicated a plan to use the handbook. Consumers Power will evaluate utility use of the handbook.

From the 10 piping systems analyzed by the handbook and verified by computer analysis, six very diverse systems were chosen that represent different routing, materials, and design requirements. The results of the evaluation indicate that support systems designed by the handbook method generally tend to have more supports than are required to meet a given set of analysis or design limits. However, handbook support locations seem to be a good basis for minimizing support.

The first two phases are now complete, and evaluation shows that a theoretical manual would considerably enhance the acceptance and use of the simplified piping handbook. In 1985 Duke Power will produce the required theoretical manual and publish the handbook, together with its manuals, for general utility use. *Project Manager: Robert E. Nickell*

New Technical Reports

Each issue of the *Journal* includes information on EPRI's recently published reports.

Inquiries on technical content may be directed to the EPRI project manager named at the end of each entry: P.O. Box 10412, Palo Alto, California 94303; (415) 855-2000.

Requests for copies of specific reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, government agencies (federal, state, local), or foreign organizations with which EPRI has an agreement for exchange of information. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of all EPRI reports on request.

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ADVANCED POWER SYSTEMS

Coproduction of Methanol and Electricity
AP-3749 Final Report (RP2029-1, -2); $19.00
Contractors: Burns and Roe–Humphreys and Glasgow Synthetic Fuels, Inc.; General Electric Co.
EPRI Project Manager: B. Louks

Fuels- and Combustion-Related Problems of Oil- and Gas-Fired Utility Boilers: An EPRI Workshop
AP-3753 Proceedings (RP1897-2); $8.50
Contractor: Energy Systems Associates
EPRI Project Manager: W. Rovesti

COAL COMBUSTION SYSTEMS

Utility FGD Survey: April–September 1983
CS-3369 Interim Report (RP982-32); Vol. 3, $23.50; Vol. 4, $28.00
Contractor: Pedco Environmental, Inc.
EPRI Project Manager: C. Dene

Coal-Water-Slurry Evaluation: Burner Test Results
CS-3413 Final Report (RP1895-3), Vol. 3; $10.00
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: R. Manfred

Nondestructive Examination of Steam Turbine Blades: An Assessment
CS-3675 Final Report (RP1266-24); $14.50
Contractor: Reinhart & Associates, Inc.
EPRI Project Manager: A. Armor

Proceedings: Eighth Symposium on Flue Gas Desulfurization
CS-3706 Proceedings (RP982-31); Vol. 1, $41.50; Vol. 2, $41.50
Contractor: Research Triangle Institute
EPRI Project Manager: T. Morasky

Biofilm Control Studies Using Ferrate and Sulfur Dioxide
CS-3708 Final Report (RP1261-3); $11.50
Contractor: University of Miami
EPRI Project Managers: W. Chow, M. Miller

Operation and Design of FGD Dampers
CS-3709 Interim Report (RP2250-1); $22.00
Contractor: Black & Veatch Engineers-Architects
EPRI Project Manager: T. Morasky

Laboratory Evaluation of Modifications to the Resox Process
CS-3710 Final Report (RP784-4); $17.50
Contractor: Foster Wheeler Development Corp.
EPRI Project Manager: T. Morasky

Sodium Conditioning for Improved Hot-Side Precipitator Performance
CS-3711 Final Report (RP724-2); Vol. 1, $13.00; Vol. 2, $10.00
Contractors: Southern Research Institute; Stearns Catalytic Corp.
EPRI Project Manager: R. Altman

Composition and Leaching of FBC Wastes at the Alliance Test Facility
CS-3715 Final Report (RP1260-39); $13.00
Contractor: Radian Corp.
EPRI Project Manager: D. Golden

Assessment of Fossil Steam Bypass Systems
CS-3717 Final Report (RP1879-1); $28.00
Contractor: Power Dynamics, Inc.
EPRI Project Manager: T. McCloskey

Continuous Emission Monitoring Guidelines
CS-3723 Interim Report (RP1961-3); $35.50
Contractor: Kilkelly Environmental Associates, Inc.
EPRI Project Manager: C. Dene

Fabric Filter Technology for Utility Coal-Fired Power Plants: Articles From the Journal of the Air Pollution Control Association, January–June 1984
CS-3724-SR Special Report; $10.00
EPRI Project Manager: R. Carr

Coal-Waste Artificial Reef Program, Phase 4B
CS-3726 Interim Report (RP1341-1); $22.00
Contractor: New York State Energy Research and Development Authority
EPRI Project Manager: D. Golden

ELECT Groundwater Transport Research Code
CS-3738 Final Report (RP1406-1); $10.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: D. Golden

Aqueous Discharges From Steam-Electric Power Plants: Trace Metal Sampling and Analysis Reference Guide
CS-3739 Final Report (RP1851-1); $22.00
Contractor: TRW, Inc.
EPRI Project Manager: W. Chow

Materials Testing in Synthetic FGD Environments
CS-3740 Final Report (RP1871-2); $17.50
Contractor: Battelle, Columbus Laboratories
EPRI Project Managers: C. Dene, B. Syrett

Aqueous Discharges From Steam-Electric Power Plants: Data Evaluation
CS-3741 Interim Report (RP1851-1); $19.00
Contractor: TRW, Inc.
EPRI Project Manager: W. Chow

Symposium on State-of-the-Art Feedwater Heater Technology
CS/NP-3743 Proceedings (RP1887-2); $37.00
Contractor: Heat Exchanger Systems, Inc.
EPRI Project Managers: R. Coit, N. Hirota

Aqueous Discharges From Steam-Electric Power Plants: Data Evaluation
CS-3741 Interim Report (RP1851-1); $19.00
Contractor: TRW, Inc.
EPRI Project Manager: W. Chow

ELECTRICAL SYSTEMS

Reliability Calculations for Interdependent Plant Outages
EL-3669 Final Report (TPS81-793); $11.50
Contractor: Energy Management Associates, Inc.
EPRI Project Manager: N. Balu

Radio Interference From HVDC Converter Stations
EL-3712 Final Report (RP1769-1); $26.50
Contractor: International Engineering Co., Inc.
EPRI Project Manager: W. Blair

Optimization of Reactive Volt-Ampere (VAR) Sources in System Planning: Solution Techniques, Computing Methods, and Results
EL-3729 Final Report (RP2109-1), Vol. 1; $19.00
Contractor: Scientific Systems, Inc.
EPRI Project Manager: N. Balu

Field Determination of PCB in Transformer Oil
EL-3766 Final Report (RP1713-1); Vol. 1, $10.00; Vol. 2, $8.50
Contractor: General Electric Co.
EPRI Project Manager: V. Tahiliani

Proceedings: Parallel Processing for Power System Planning and Operations
EL-3775 Proceedings (WS79-179); $25.00
EPRI Project Manager: J. Lamont

Load Transfer Mechanisms in Rock Sockets and Anchors
EL-3777 Final Report (RP1493-1); $13.00
Contractor: Cornell University
EPRI Project Manager: V. Longo

ENERGY ANALYSIS AND ENVIRONMENT

Integrated Lake-Watershed Acidification Study: Summary of Major Results
EA-3221 Final Report (RP1109-5), Vol. 4; $19.00
Contractor: Tetra Tech, Inc.
EPRI Project Manager: R. Goldstein

Geohydrochemical Models for Solute Migration: Preliminary Evaluation of Selected Computer Codes
EA-3417 Final Report (RP2485-2, RP1619-1), Vol. 2; $28.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: I. Murarka

Linking Market Planning to Corporate Objectives: Utility Case Study
EA-3736 Final Report (RP1634); $10.00
Contractor: Booz, Allen & Hamilton, Inc.
EPRI Project Manager: D. Geraghty

Coal-Cleaning and Coal Slurry Wastewater: Literature Review
EA-3770 Final Report (RP2377-1); $14.50
Contractor: University of Tennessee
EPRI Project Manager: I. Murarka

ENERGY MANAGEMENT AND UTILIZATION

500-kW Lead-Acid Battery for Peak-Shaving Energy Storage Testing and Evaluation
EM-3707 Interim Report (RP2123-2); $10.00
Contractor: GNB Batteries Inc.
EPRI Project Manager: W. Spindler

NUCLEAR POWER

Evaluation of Alternative Alloys for PWR Steam Generator Tubing
NP-3703 Final Report (RP1450-1); $16.00
Contractor: Inco Alloy Products Co. Research Center
EPRI Project Manager: C. Shoemaker

Generation and Behavior of Metal Oxide Colloids in PWR Steam Systems
NP-3718 Topical Report (RP966-2); $10.00
Contractor: Calgon Corp.
EPRI Project Manager: T. Passell

Analysis of the Browns Ferry Unit 3 Irradiation Experiments
NP-3719 Final Report (RP827-1); $13.00
Contractor: Science Applications, Inc.
EPRI Project Manager: T. Passell

Proceedings: Technology Transfer Seminars
NP-3721-SR Special Report; $16.00
EPRI Project Manager: G. Dau

Guidelines for PWR Pressure Protection System Optimization
NP-3734 Final Report (RP2007-1); $22.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: B. Brooks

New Computer Software

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ACPIPE—Powerline-Induced Ac Potential on Natural Gas Pipelines for Complex Rights-of-Way
Version 1.1 (IBM)
Contractor: Science Applications, Inc.
EPRI Project Manager: John Dunlap

BRODI2/BROFLX—Transmission Line Broken Wire
Version 2.2 (IBM)
Contractor: GAI Consultants, Inc.
EPRI Project Manager: Paul Lyons

CMCM—Coal Mine Cost Model
Version 3.0 (IBM)
Contractor: NUS Corporation
EPRI Project Manager: Jerome Delson

DETGEN—Decision Tree Generator Model
Version 1.0 (generic use)
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: Lewis Rubin

ELM—End-Use Load Modifier
Version 1.2 (IBM)
Contractor: Decision Focus, Inc.
EPRI Project Manager: Victor Niemeyer

HELM—Hourly Electric Load Model
Version 1.0 (generic use)
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: Ahmad Faruqui

SYREL—Transmission System Reliability Methods
Version 1.2 (PRIME)
Contractor: Power Technologies, Inc.
EPRI Project Manager: Neal Balu

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