Fuel Cells: The Commercial Challenge

ELECTRIC POWER RESEARCH INSTITUTE

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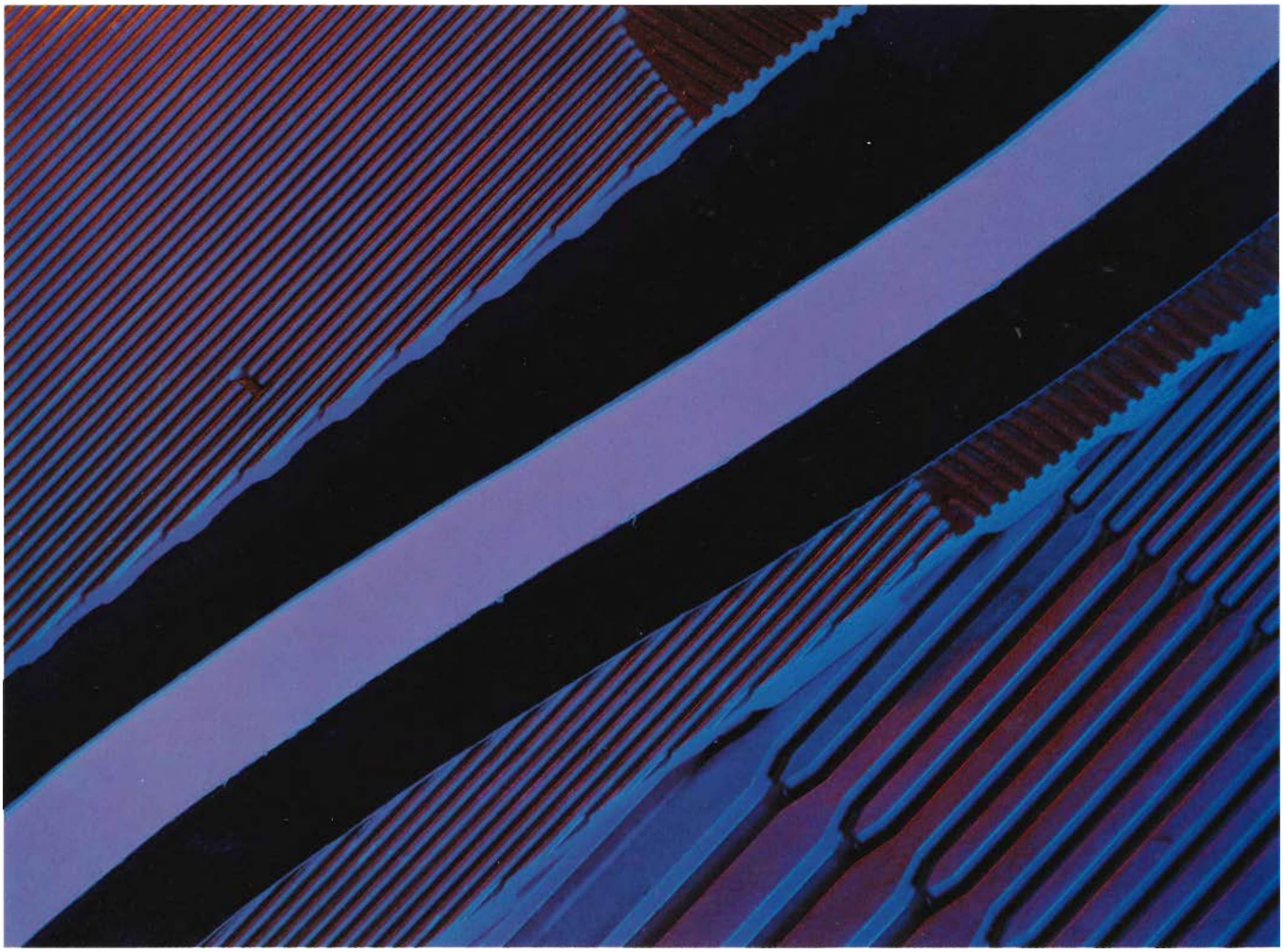

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EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution, and utilization.

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Cover: Cutaway view of a Westinghouse Electric Corp. phosphoric acid fuel cell shows its electrodes, electrolyte matrix, and fuel-air distribution plates. Hundreds of these flat cells are stacked to make up the power modules of a fuel cell power plant.

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The Move to Commercialization

Ten years ago, many of us believed that as new technologies offering substantial benefits were developed, the industry would wholeheartedly welcome these technologies into its systems. Indeed, during its first decade, EPRI directed most of its effort toward developing and demonstrating new and improved power generation and energy storage technologies, assuming that the move to commercialization would take care of itself. Perhaps naively, we underestimated the gap that separates a demonstrated technology from a commercially acceptable product. Furthermore, although several technologies, including the fuel cell, are now at the brink of commercial use, this gap has been widened by reduced load growth, an unpredictable fuel supply, high interest rates, and a difficult regulatory climate—all factors that work against the introduction of new technology.

Thus, as we stand ready to commercialize the fuel cell, we are facing a challenge that was unanticipated when EPRI was founded. This challenge has certain characteristics that will be common to other new generation and storage technologies. Initial units will have higher costs and/or risks than subsequent units. Utilities, for good reason, are reluctant to pioneer new technology, especially if that means accepting extraordinary costs or risks. And suppliers, for equally good reason, are not bullish on the electric utility industry as a business opportunity. Yet by the mid-1990s, the utility industry will need new technology options if it is to meet the demand for electricity in a cost-effective, reliable, and environmentally acceptable manner.

To bring these technologies to commercial use, EPRI must stretch beyond its research and development focus and address the marketplace. This will require rethinking priorities and asking its technical staff to accept an expanded and more complicated role. It will mean adding commercialization resources to EPRI's capabilities. It will mean working with the industry to encourage pioneering utilities to step forward and accept somewhat greater initial costs and risks today in order to obtain lower costs, improved reliability, and a better environment for tomorrow. It will also mean assisting suppliers by defining market opportunities to mitigate market risks.

Our fuel cell program is well positioned to meet this challenge. Manufacturers in both the United States and Japan are committed to electric utility fuel cell power plants as a business opportunity. Furthermore, beginning about four years ago, we assisted the industry in forming the Fuel Cell Users Group to address many of the commercialization issues. With the help of the users group, we conducted a series of market application and commercialization analyses. And we have provided for future resources to assist pioneering utilities and suppliers by reducing the costs and risks inherent in early units.

We cannot be certain that these efforts will be sufficient to put fuel cell power plants on utility systems—the challenge remains formidable and the path is uncharted—but we can expect an exciting second decade at EPRI as fuel cells and other energy technologies approach commercialization.

Arnold P Fickett

Arnold P. Fickett, Director
Advanced Conversion and Storage
Energy Management and Utilization Division

Authors and Articles

Bringing the fuel cell down to earth from its first operational success in NASA's Gemini missions has taken 20 years, but the results should be right on time for electric utilities as they begin to need clean power in relatively small increments, especially for urban sites. **Fuel Cells for the '90s** (page 6) is this month's lead article, in which Nadine Lihach, the *Journal's* senior feature writer, reviews the major R&D moves by government, utility, and industry sponsors here and in Japan. Background for the article came from EPRI's Arnold Fickett and Edward Gillis.

Fickett has been director of the Advanced Conversion and Storage Department in the Energy Management and Utilization Division since 1981, after seven years of principal responsibility for EPRI's fuel cell R&D. Before joining the Institute in April 1974, Fickett was with General Electric Co. for 18 years, where he was involved in fuel cell and other electrochemical development projects. Between 1970 and 1974 he was manager of engineering for General Electric's direct energy conversion programs.

Gillis, program manager for fuel cells and chemical energy conversion R&D, came to EPRI in 1976. He was formerly with the Army's Mobility Equipment R&D Command for 12 years, ultimately as chief of the electrochemical division. From 1958 to 1964, Gillis was with Allis-Chalmers Corp., where he became a project engineer in fuel cell development. He is a mechanical engineering graduate of Marquette University.

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Intergranular stress corrosion cracking (IGSCC) of certain nuclear reactor piping, recognized as a generic problem only in the last 10 years, has yielded to systematic research in the last 5. **BWR Pipe Integrity** (page 14), by science writer John Douglas, traces the chronology and scope of remedial efforts dealing with materials, water chemistry, welding stresses, and the all-important inspections that signal success or failure. Four research managers from three programs of EPRI's Nuclear Power Division contributed to the article.

Gary Dau, who heads the Structural Integrity Program, has been with EPRI since April 1977. Previously he worked for 12 years at Battelle, Pacific Northwest Laboratories in nuclear instrumentation and nondestructive examination—a specialty in which he continues today. Dau holds a BS in mechanical engineering from the University of Idaho and a PhD in nuclear engineering from the University of Arizona.

Adrian Roberts, senior manager of the Fuels and Materials Program, joined EPRI in September 1974 after six years in the materials science division of Argonne National Laboratory, where he led research in fuel and other materials for fast reactors. Roberts holds BS, MS, and PhD degrees in metallurgy from Manchester University (England).

Joseph Danko is senior program manager for IGSCC research in cooperation with the Boiling Water Reactor Owners Group. An EPRI staff member since October 1978, he formerly was with General Electric Co. for 16 years, including 7 as manager of materials and process development in the nuclear technology department. A graduate of Carnegie-Mellon University in metallurgical engineering, Danko earned an MS and a PhD in the same field at Lehigh University.

Soung-Nan Liu, who manages projects in nondestructive evaluation, came to EPRI in March 1980, following three years as a vice president of Holosonic, Inc., a manufacturer of ultrasonic instrumentation. From 1973 to 1977 he was with Battelle, Pacific Northwest Laboratories, managing research and coordinating projects in the Far East. Still earlier, Liu worked for six years as a project engineer with John Graham and Co. (Seattle). He studied as an undergraduate at Taipei Institute of Technology (Taiwan), and later earned MS and PhD degrees in structural mechanics at the University of Arizona and the University of Washington.

■

Computers are ready to control almost anything: their sheer power and programming sophistication are exceeding popular expectations. Routinely applying that control throughout an electric utility distribution network is something else, however. **Automating the Distribution Network** (page 22) reviews R&D that is methodically addressing the problems of communication links, specialized software, and hardware that will respond to the new messages. Taylor Moore, *Journal* feature writer, turned to William Blair of EPRI's Electrical Systems Division for background.

Blair, a project manager in the Distribution Program, joined the Institute staff in May 1976, following nearly 12 years with SRI International as a research engineer in detection and communication techniques, apparatus, and systems throughout the frequency spectrum. He holds BS and MS degrees in electrical engineering from Cornell University and a DSc degree in electrical engineering from the University of New Mexico.

■

Adapting electrostatic precipitators to capture fly ash particles efficiently from the exhaust gases of low-sulfur coals has required special effort because of generally higher particle resistivity. **Restoring ESP Performance: The Sodium Fix** (page 29), by science writer Stephen Tracy, explains the effect of sodium compounds on low-sulfur coal combustion and its products. Tracy developed the article with assistance from Robert Carr and Ralph Altman of EPRI's Coal Combustion Systems Division.

Carr has managed the Air Quality Control Program since April 1982. He came to EPRI in March 1974 after two years with KVB, Inc., as a test engineer and consultant to utilities on emission controls. Carr began his work in emission measurement and analysis as a research assistant at the University of California at Berkeley, where he earned BS and MS degrees in mechanical engineering.

Altman, a project manager at EPRI's southeastern office in Chattanooga since September 1978, was formerly a research engineer for three years at the Georgia Institute of Technology Experiment Station. Before that he was a stress analyst on fossil fuel boiler design at Combustion Engineering, Inc. A mechanical engineering graduate of Georgia Tech, he returned there for MS and PhD degrees in physics.


Fickett


Gillis


Liu


Blair


Danko


Roberts

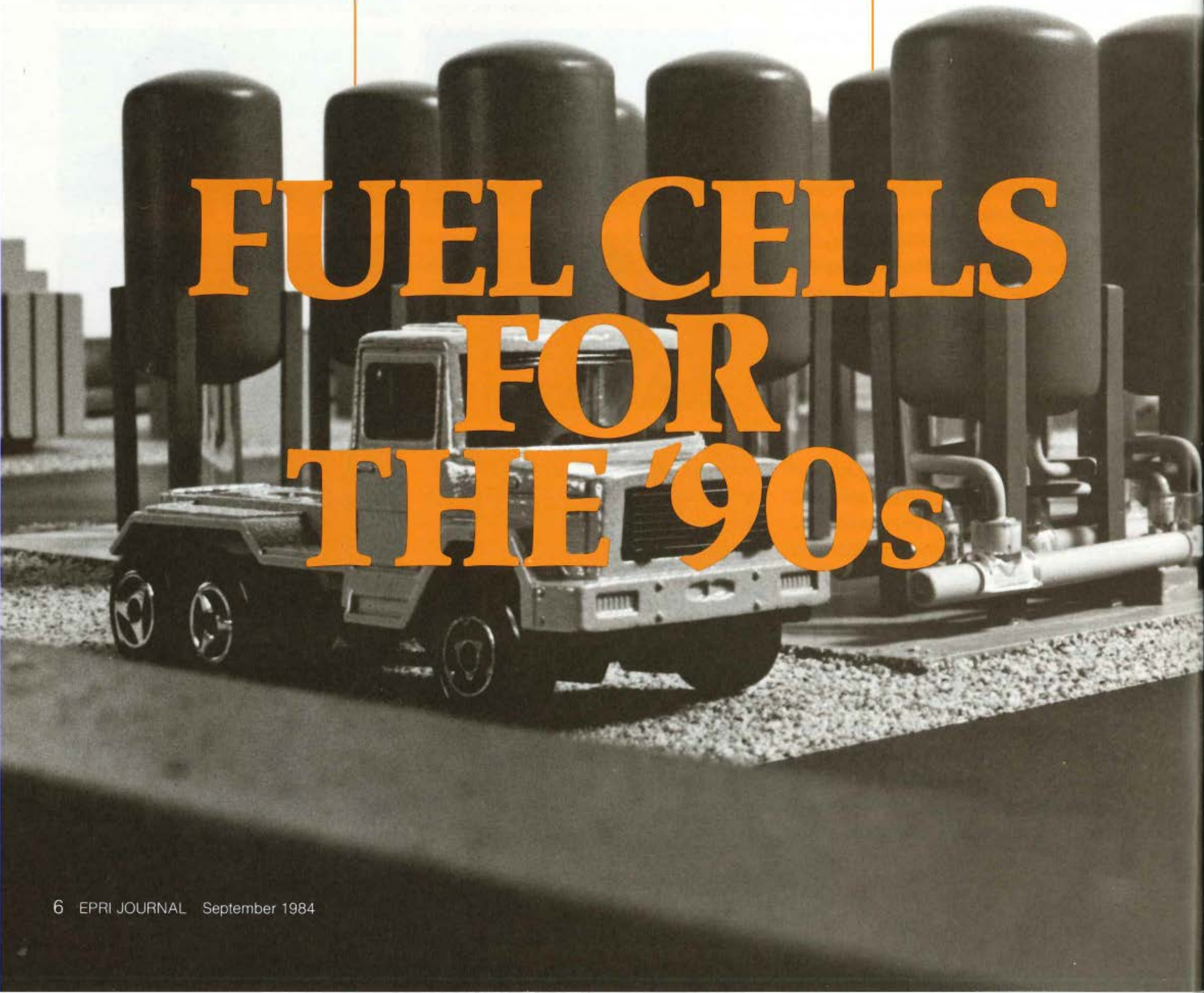

Carr


Dau


Altman

It's taken years
of determined R&D by utilities,
manufacturers, and government,
but the fuel cell power plant
is going to be there
when the industry needs it most.

FUEL CELLS FOR THE '90s



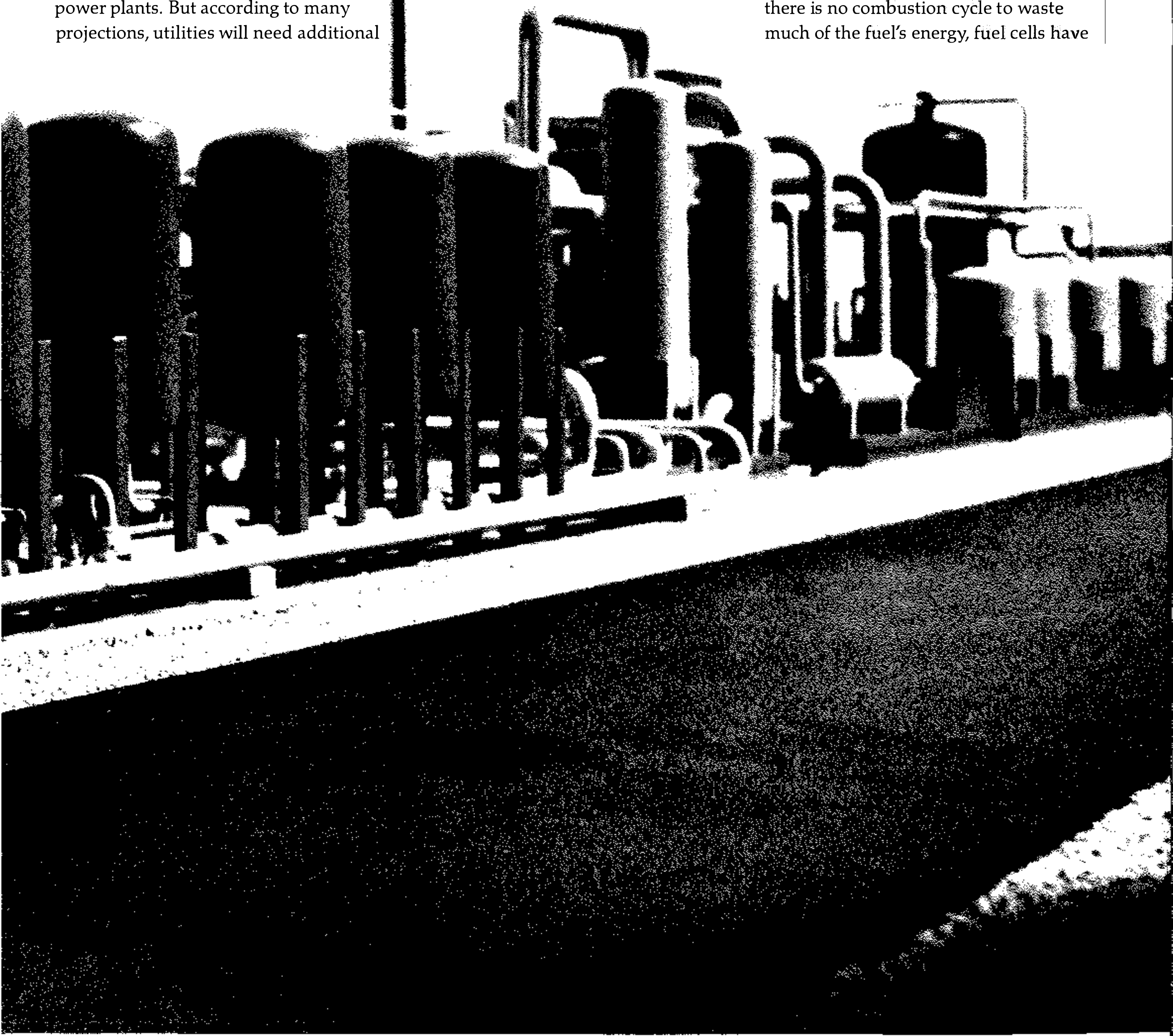
Good ideas don't always catch on quickly or easily, but when they do, the wait is worth it. The fuel cell, which combines fuel and oxygen without combustion to produce electricity cleanly and efficiently, is one of the good ideas that's taken a long time to develop. Electric utilities will soon agree that the wait was worthwhile, because the fuel cell is specially qualified to help many of them out of a tight spot they are likely to be in only a few years from now.

Tight spot

Because of uncertain load growth, high construction costs, and frugal utility budgets, few utilities are building new power plants. But according to many projections, utilities will need additional generation capacity beginning in the late 1980s, particularly in urban and suburban areas.

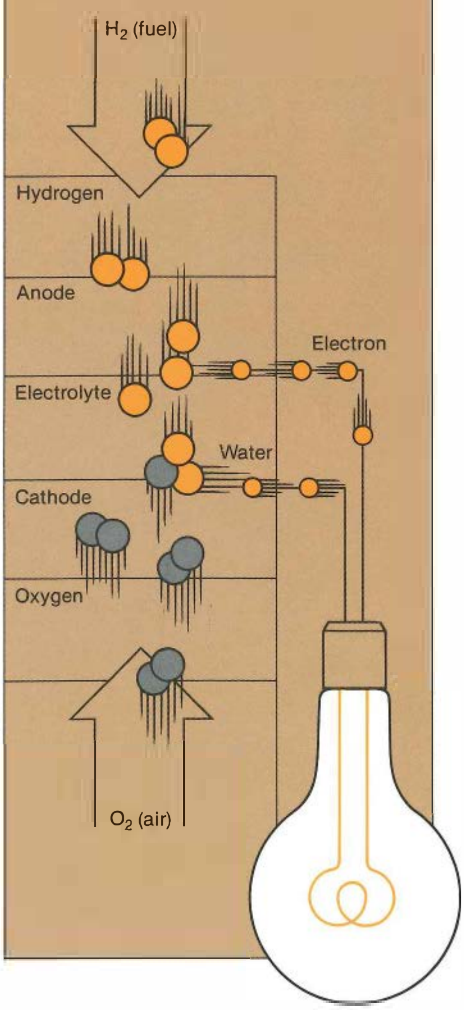
When the need strikes, it will be too late to build conventional coal or nuclear stations. These take 10–12 years to construct, and they will not be permitted in densely populated areas. Combustion turbines can be constructed in 2–3 years, but they burn costly oil and gas inefficiently. Nontraditional alternatives—plants that can be ordered up quickly and in modular increments as needed, plants without emissions to trouble neighbors, plants that use fuels more efficiently—will be necessary to help utilities out of their predicament.

The fuel cell is exactly such an alternative. Fuel cell power plants can be built in small factory-assembled modules and installed in just 2 or 3 years, explains Arnold Fickett, director of EPRI's fuel cell research. More modules can be added as utility need and finances dictate. Because the fuel cell converts fuel—oil, gas, even coal distillates and other synthetic fuels—directly to electricity without combustion, it has virtually no sulfur and nitrogen oxide emissions, only carbon dioxide, water, and air. With no harmful emissions, fuel cells can be sited in populated areas. And because there is no combustion cycle to waste much of the fuel's energy, fuel cells have



ELECTRICITY WITHOUT COMBUSTION

The fuel cell electrochemically combines fuel and oxygen to produce electricity. Fuel gas flows across the cell's fuel electrode (anode), where it separates into hydrogen ions and electrons. The ions migrate through the electrolyte to the oxygen electrode (cathode), while the electrons move through an external circuit to the cathode. Oxygen, hydrogen ions, and electrons join at the cathode to form water. The flow of electrons through the external circuit produces electricity. A fuel cell power plant may contain thousands of these individual cells stacked within its power section. A fuel processor converts such utility fuels as natural gas, light distillates, or synthetics to the hydrogen-rich fuel necessary for the cells, and a power conditioner converts the resulting direct-current electricity to alternating-current electricity.

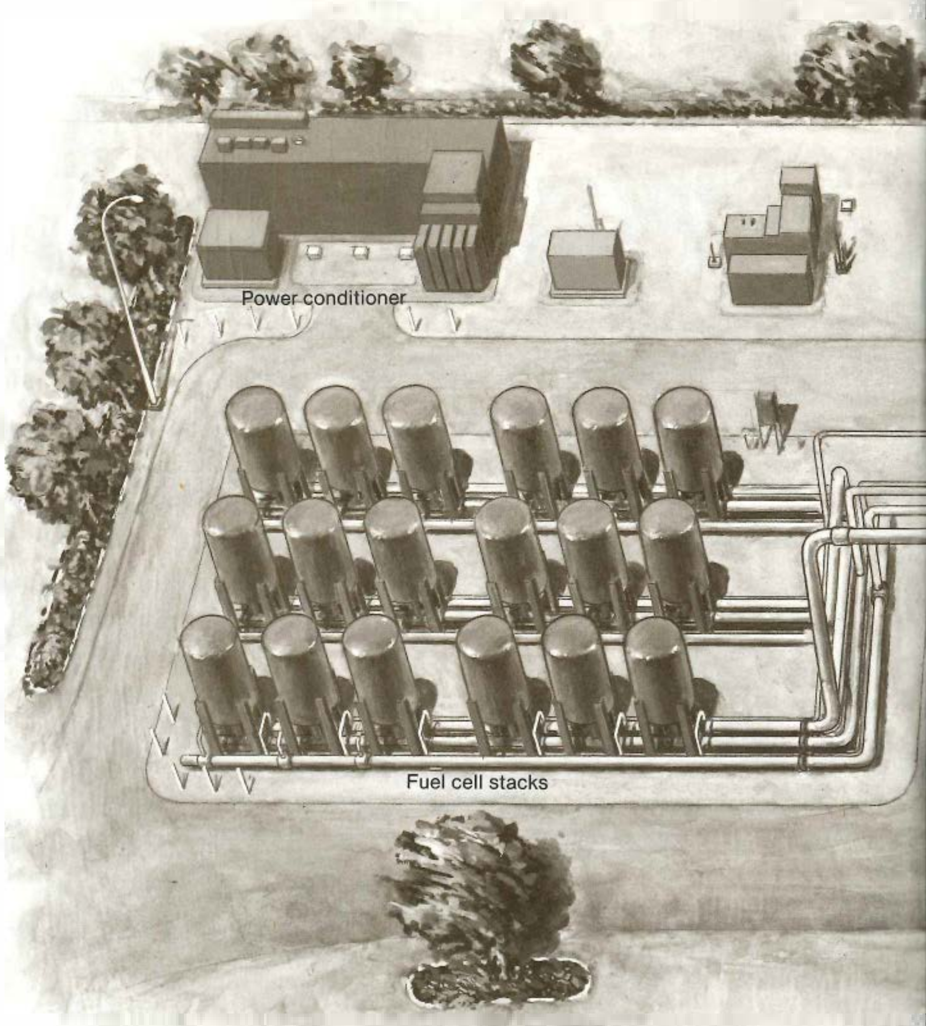


WHAT'S NEW IN COMMERCIAL FUEL CELL POWER PLANTS

The fuel cell power plants that utilities buy just a few years from now will not only be technically improved but will also be less complex and less costly than the New York City and Tokyo demonstrators. This schematic features an up-to-date UTC design for an 11-MW plant with numerous improvements.

The heat rate of the 11-MW design is 8300 Btu/kWh—a full 1000 Btu/kWh lower than that of the demonstrators. This heat rate is essentially constant between 50 and 100% of rated power, and the plant can operate as low as 30% of rated power.

Unnecessary performance features have been eliminated. For example, the demonstrators were designed to respond to load transients in a scant 0.3 second. The 11-MW unit is permitted 1 second to respond to every 1-MW change in load.



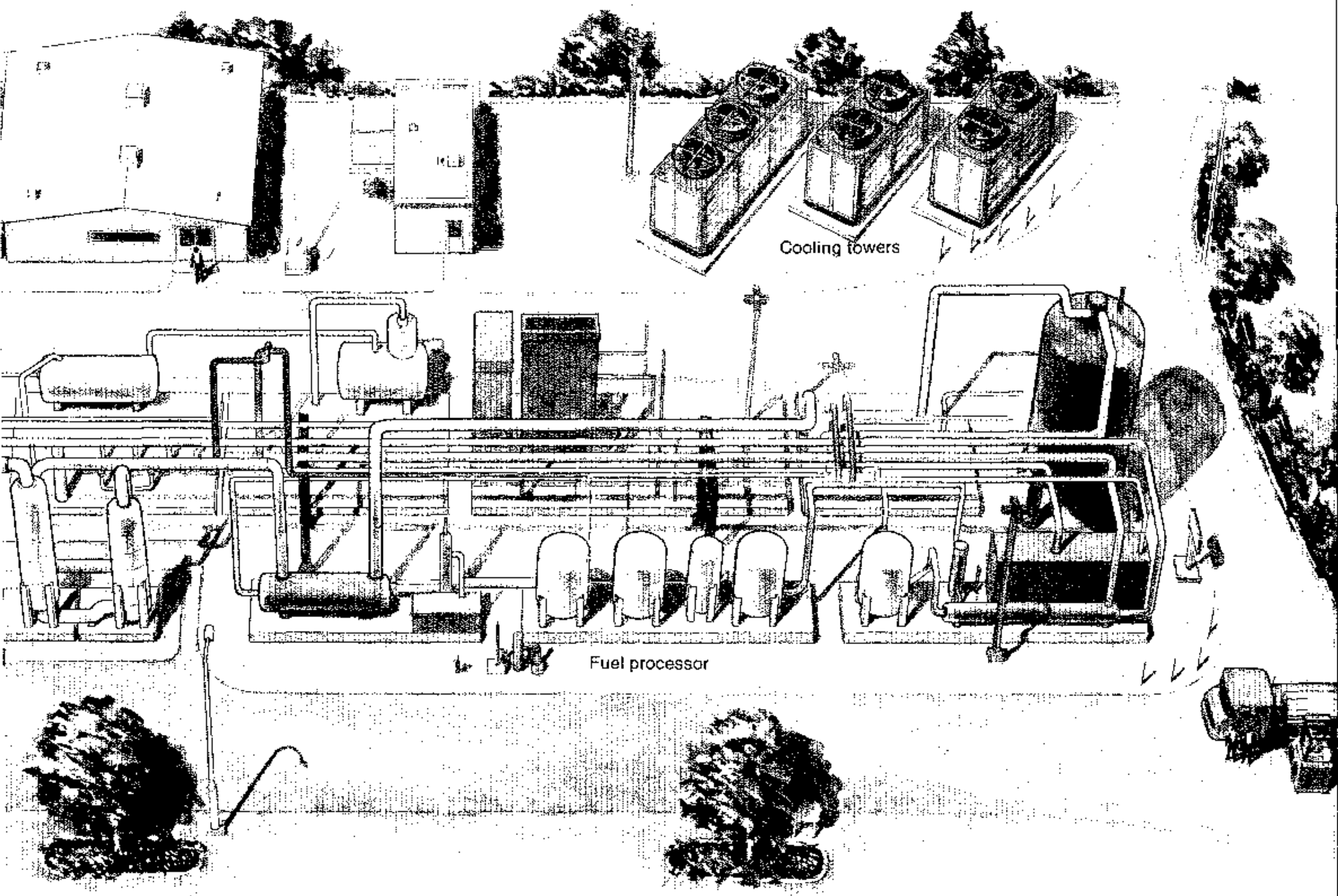
State-of-the-art fuel cell stacks offer unlimited shelf life.

The area of the individual fuel cells has been increased to 10 ft² from the 3.7 ft² of the demonstrators, making it less complicated and less costly to fabricate full stacks.

System simplification studies have enabled the 11-MW design to dispense with 37% of the components used in the demonstrators, including power section pallet enclosures, several process gas regenerators, and numerous process gas flow controls.

Many components that were custom-designed and custom-fabricated for the demonstrators —turbocompressors and heat exchangers, for example—have been replaced by commercial components.

The new design's operating pressures and temperatures are substantially higher than those of the demonstrators, which allows doubling of the demonstrators' power output without having to change the size of many components.



Emissions from the 11-MW plant are minimal: 0.035 lb of nitrogen oxides and 0.0003 lb of sulfur oxides per million Btu of fuel used. The plant produces no smoke or particulates.

The 11-MW design is fully truck-transportable and occupies only about 1.2 acres. Access to components has been improved to facilitate maintenance.

potentially higher efficiencies than any thermal plant around.

Best of all, the fuel cell will be on hand to deliver these benefits. In the past 12 years intensive development by EPRI, DOE, utilities, manufacturers, and a fuel cell users group has taken the fuel cell all the way from the laboratory to a 1-MW test to twin 4.8-MW demonstrators in New York City and Tokyo. Designs are now being drawn for commercial power plants that promise to meet the operational, environmental, and siting requirements of the utility industry. Two major U.S. manufacturers, United Technologies Corp. (UTC) and Westinghouse Electric Corp., are positioning themselves to offer commercial fuel cell power plants to utilities only a few years from now, and a number of Japanese firms are preparing to do the same.

Getting the fuel cell to this point took nothing less than determined R&D. The first fuel cell power plants were built and field-tested in the early 1970s by a group of gas and gas-electric utilities that saw small on-site fuel cell power plants as a way of converting natural gas to electricity and thermal energy for residential and commercial customers. These plants were pint-sized by electric utility standards—most were rated 12.5 kW—but they worked and thus attracted the attention of the electric utility industry.

In 1972 UTC and nine electric utilities initiated a program to develop a large-scale, first-generation phosphoric acid fuel cell plant suitable for supplying electricity to entire cities. By 1977 the utilities and UTC had successfully demonstrated a 1-MW pilot plant that confirmed that a naphtha-fueled unit could indeed provide electricity to a utility bus while meeting heat rate, load-following, emissions, and other utility operational requirements.

Demonstrated ability

But utilities needed further verification of the fuel cell's operational, environmental, and siting claims, and that required a still-larger, transportable plant connected to an actual utility grid. In 1976 the utilities and UTC convinced EPRI and ERDA (now DOE) to fund a multimillion-dollar program to design, manufacture, and test a 4.5-MW ac (4.8-MW dc) power plant demonstrator.

The demonstrator was to be connected to a utility grid and operated by utility personnel, not research engineers. Data on the fuel cell's emissions, noise levels, and general neighborhood acceptability were to be collected, and economic advantages—including transmission savings, voltage control, load following, and system reliability—identified. The demonstrator was also to double-check the fuel cell's operational claims, including heat rate, power quality, transient response, and startup-shutdown characteristics. All plant components were to be organized into modules that could be loaded onto pallets and transported to the site by truck, just as they would be in a commercial plant.

But ambitious as the demonstrator was, it was not a true commercial prototype. "Utilities knew that the cost of the plant would have to be brought down, the endurance of the cell stacks improved, and many other details taken care of," recalls Edward Gillis, EPRI fuel cell program manager. To keep fuel cell technology moving past the demonstrator stage, DOE and EPRI commissioned UTC to improve cell stack technology and design a commercial fuel cell plant at the same time the company was designing and constructing the 4.8-MW demonstrator. The experiences of the demonstrator would be incorporated into UTC's commercial design.

One important fuel cell claim that utilities wanted the demonstrator to make good on was easy siting, licensing, and public acceptance, so when Consolidated Edison Co. of New York, Inc., proposed a utility lot in Manhattan's densely populated Lower East Side as the future home for the unit, EPRI and DOE agreed it was worth the challenge. In 1978 project host Con Ed began to seek permission to build the demonstrator on the site.

This turned out to be a challenging test of the fuel cell's merits. Although the demonstrator was to be noiseless and emission-free, nearby residents were concerned about possible fire hazards from on-site fuel processing and fuel storage. Despite reassurances that any hazards were minimal, a lengthy debate ensued. Plant design and construction proceeded, but it took three years of reviews, special tests, and extensive design studies for the New York City Fire Department to fully approve the installation. Yet in the end, utilities saw an all-new power plant installed in downtown New York City.

U.S. utilities were not the only observers following the demonstrator's licensing and construction progress: Japanese utilities, inescapably dependent on costly oil and gas for electricity and beset by serious emissions problems, had even more to gain from fuel cells than their American counterparts. In early 1980, as equipment pallets were being installed in New York City, Japan's Tokyo Electric Power Co. (Tepco) announced that it would install its own fuel cell demonstrator, with UTC's help.

Tokyo takes advantage

The demonstrator Tepco ordered from UTC was essentially a twin of the New York City unit, and the Japanese objective was the same as that of the U.S. project: to show local utilities what the fuel cell could do. But although the units were twins, they were not identical. The Tepco unit would have the benefit of the New York City demonstrator's engineering experiences and would also be able to use the advanced fuel cell stacks that UTC had developed since the New York City unit was commissioned. Furthermore, the Japanese unit was to be constructed on an existing power plant site near Tokyo, so siting permits were less of a problem. This meant the Tepco demonstrator would be spared the special reviews and tests that had delayed the downtown New York City unit.

While Tepco moved ahead with its plans, construction continued at the Manhattan site and demonstrator startup tests began in November 1981. Although the tests were periodically interrupted by equipment problems typical of any new technology, all checkout requirements had been successfully completed by mid 1983, including integrated operation of all systems (except the fuel cell power section) under simulated load-producing conditions.

Back in Tokyo the Tepco demonstrator was off to a running start. The experiences of the New York City fuel cell enabled the Japanese to move their unit quickly through its critical stages. Construction was completed in early 1982, less than 24 months after groundbreaking. Checkout tests were completed later that same year, and in early 1983 the advanced fuel cell stacks had successfully produced power. The Tepco demonstrator was operated between 25 and 100% of rated power, producing utility-quality power and only minimal emissions.

A little later that year, the early-design fuel cell stacks were put in place in New York City, and in April 1984 Con Ed attempted to produce power. But the plant would not start: some of the phosphoric acid electrolyte of these early cells, contained in a porous substance layered between the electrodes, had migrated away from the electrodes. Engineers had known this would eventually happen in the early cells, but they had expected the plant to be running before then; what hadn't been anticipated were the unusually long licensing and plant activation delays. The cell stack used in the Tepco unit has virtually unlimited storage life, and Con Ed and UTC have recently asked Congress for funds to retrofit the New York City unit with the improved stacks.

The New York City demonstrator did not produce power, but the Tokyo unit, building on the experiences of the New York unit, did. Between the two of them, the demonstrators showed that a fuel cell power plant could be successfully sited by a utility company in an environmentally constrained urban setting, and that it could be installed, checked out, and operated over its full range of conditions by utility personnel. Long-term operation still needed to be demonstrated—and Tepco planned to conduct an endurance test program through the remainder of 1984—but it was now time to advance from demonstrators to commercial configurations.

Next: commercial designs

Designs for commercial fuel cell power plants had been moving steadily forward while the New York and Tokyo demonstrators were being built. On the basis of input from the Fuel Cell Users Group, made up of about 60 individual utilities and utility organizations, UTC engineers knew that utilities were looking for a commercial plant that had even better performance; simpler installation, operation, and maintenance; and a lower overall cost. It was a tall order, demanding

FUEL CELL FLEXIBILITY

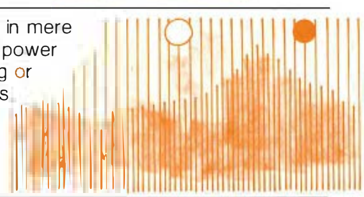
All-around flexibility is the reason why utilities will be shopping for the fuel cell instead of more traditional power plants later this decade.

Planning: Modular fuel cell power plants can be manufactured, delivered, and assembled within two years of ordering. This short lead time permits utilities concerned about uncertain load growth and/or finances to wait as long as possible before committing to new generating capacity. New modules can be added as needed.

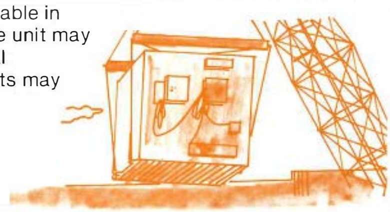
Siting: Because fuel cell power plants produce energy by electrochemistry rather than combustion, they produce few sulfur and nitrogen oxide emissions. The fuel cell also operates quietly. These features will permit fuel cells to be built close to urban and suburban loads, which in turn will save on transmission facilities and permit cogeneration.

Fuel: The fuel cell power plant can convert oil, natural gas, or synthetics to hydrogen-rich fuels for its cells. In more remote areas, coal gasification plants can provide fuel for the cells.

Dispatch: The fuel cell responds to load changes in mere seconds and is highly efficient whether run at full power or part power. This means it can work as a peaking or intermediate unit to replace older, inefficient plants.



Modularity: Fuel cell power plants will be available in small basic units of about 10 MW each. A single unit may be installed to serve a commercial or residential complex, or a larger plant made up of many units may be assembled to serve a whole city.



significant design modifications, but by late 1982 UTC had come up with a generic design for a commercial 11-MW fuel cell plant whose technology was considerably less complex and relatively less costly than that of the demonstrators—in short, a plant more suited to utility preferences and pocketbooks.

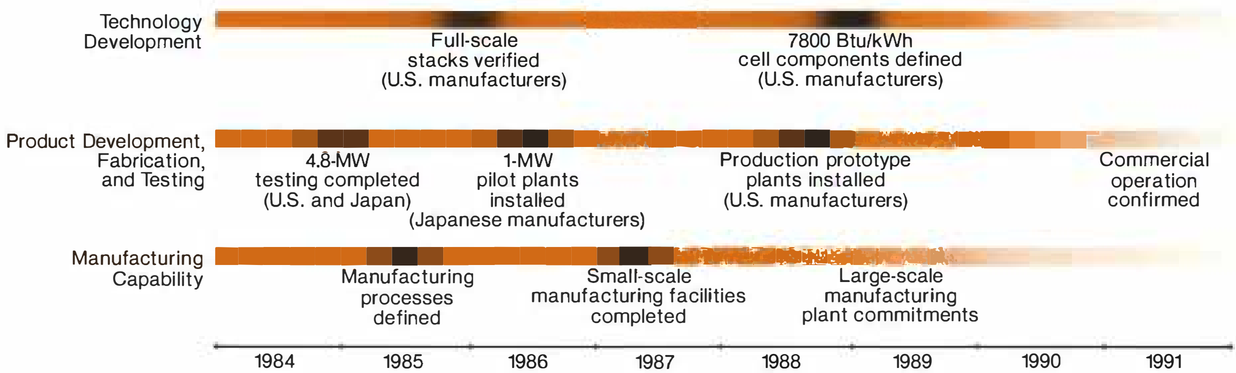
By increasing plant operating pressures and temperatures, UTC was able to more than double the demonstrator's power output without having to change many components. Increased pressure and temperature also meant that the total fuel cell area needed to be increased by only about 60% to achieve that doubled output, again saving on components. And UTC was able to develop cells with an increased area—10 ft² (0.929 m²) as opposed to 3.7 ft² (0.344 m²)—which further cut back on components. The end result was more power at less cost. As for the overall plant design, system simplification studies resulted in 37% fewer components than the New York City demonstrator had, again cutting cost and simplifying installation, operation, and maintenance.

UTC further economized by replacing many custom-designed and -fabricated components with commercial components. For example, high-efficiency turbocompressors for pressurizing the system are now commercially available, and these were included in the design instead of the made-to-order turbocompressors that went into the demonstrators. The new plant design also eliminated some performance features that were considered nonessential for utility operations. For instance, the New York and Tokyo units were designed to respond to load transients in a bare 0.3 second; UTC's 11-MW design takes 1 second to respond to every 1-MW change in load—still fast, but much simpler to control and therefore less expensive.

Taken together, the improved stack technology, system simplifications, and extensive use of commercial components lowered the specific cost for first produc-

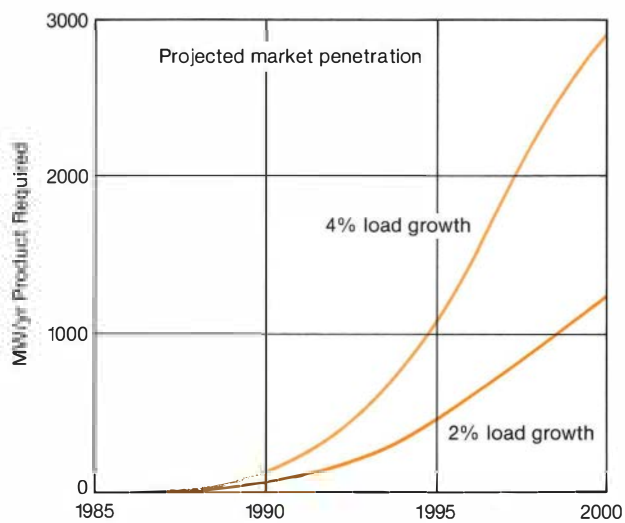
The fuel cell power plant is on a tight schedule for utility service by the early 1990s. Both U.S. and Japanese manufacturers are now developing the fuel cell for the commercial market, and prototype plants should be installed sometime in the late 1980s. Before substantial numbers of fuel cell power plants can be ordered, large-scale factories must be established. Load growth is important to how far the fuel cell will go: according to one projection, a 2% growth rate would require about 500 MW of fuel cell power plants a year by 1996; doubling load growth to 4% would require 500 MW a year by 1993.

First-Generation Fuel Cell Commercialization Schedule



New York City

Tokyo



tion units by more than 50% relative to the technology used in the 4.8-MW demonstrator.

UTC is now developing the 11-MW design further so that it can serve as a commercial prototype. Meanwhile, another U.S. manufacturer is coming up with a commercial design of its own. Westinghouse had been quietly researching the fuel cell since the 1960s, and by the late 1970s, encouraged by its results and heartened by growing utility interest, the firm decided to develop and produce its own fuel cell power plant.

In 1980, with DOE and EPRI support, Westinghouse's Advanced Energy Systems Division began to design a 7.5-MW fuel cell power plant module, a commercial prototype that will be offered to utilities in a few years. Westinghouse and Southern California Edison Co. have recently agreed to build the first of these units on the utility's system if an advanced 100-kW stack performs satisfactorily in upcoming tests. The prototype could probably start operation by 1988, and Westinghouse would then offer it to other utilities.

Overseas, the Japanese government and manufacturers have also been pushing the fuel cell toward commercial status. The New Energy Development Organization, a federal agency similar to DOE, is now supporting the design and construction of two 1-MW pilot plants for operation on utility systems by 1986. The units will eventually be scaled up to 10-MW demonstrators and then to full-size plants for utility service by about 1990.

Each pilot plant is the product of a different team made up of two major Japanese manufacturers. The plant being developed by Fuji Electric Co., Ltd., and Mitsubishi Electric Corp. is destined for use in a 30–50-MW plant for dispersed electricity generation and cogeneration; the plant planned by Hitachi, Ltd., and Toshiba Corp. will operate at somewhat higher temperatures and pressures and is intended for central generating stations over 50 MW. All the members of the team have access to each other's technology.

Almost here

It won't be long now before manufacturers in both the United States and Japan offer commercial fuel cell power plants to utilities. UTC will be ready to offer the fuel cell in 11-MW commercial modules in the next two years, forecasts Arnold Fickett, and Westinghouse will be able to offer 7.5-MW modules within a few more years. Japanese manufacturers will probably make offerings at about the same time.

If manufacturers are able to supply the fuel cell at a competitive price, utilities will almost surely buy it. A 1984 EPRI study projected that a cost-competitive fuel cell plant will have a potential utility market of 35,000–65,000 MW from 1986 to 2005. But before any market develops, the fuel cell's supporters must solve that perennial market problem: who buys the high-cost early units. The first fuel cell plants will be manufactured a few at a time until enough sales volume builds up to justify a fully automated factory. These units will be more costly to produce than those from automated factories, so the first intrepid customers will have to pay more for their plants—possibly around $3000/kW. Later customers may get mass-produced fuel cell plants for a reasonable $1000/kW or less. It's hard enough for a utility to order the prototype of a new generating unit, but tougher still when there's a premium to pay.

Right now, utilities seem to be waiting to see who goes first. But there is a danger in waiting too long: utilities will begin to feel the need for new generation units in the late 1980s, and fuel cell demand may be great in the mid-1990s. If fuel cells are going to be there to serve utilities, commercial prototypes will have to go on-line soon. These prototypes should resolve the few last technical problems and help persuade other utilities to buy into the market so that manufacturers can build their factories. Waiting too long may also lead manufacturers to conclude that there is not enough of a market for the fuel cell, and they may redirect their investments elsewhere.

The Fuel Cell Users Group is now figuring out how to get around this who-goes-first impasse. "One possibility is cost-sharing by utilities and EPRI to help the first buyers fund their high-priced units," says Robert Fri, adviser to the group's board of directors and until recently executive director. Another possibility is to persuade manufacturers that the market is secure enough for them to evenly distribute the cost of commercialization over a large number of units. The users group recently held regional meetings to assess serious utility interest, and the findings will be presented to manufacturers shortly.

The wait for the fuel cell has indeed been long, but Arnold Fickett, a fuel cell proponent since the days of the early space missions, is confident that the cell will make it. All that's required is a nudge in the right direction. The need is there, as user-group enthusiasm attests; the technology is just about ready, proved by demonstration in the field and refined by later design studies; and major manufacturers in both the United States and Japan are preparing to move, given reasonable confidence in the market. "The fuel cell is going to go commercial," concludes Fickett. "A plant with that much to offer the utility industry just can't fail." ■

Further reading

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Kaplan, Gadi. "New York's Fuel Cell Power Plant: On the Verge of Success." *IEEE Spectrum*, December 1983, pp. 60–65.

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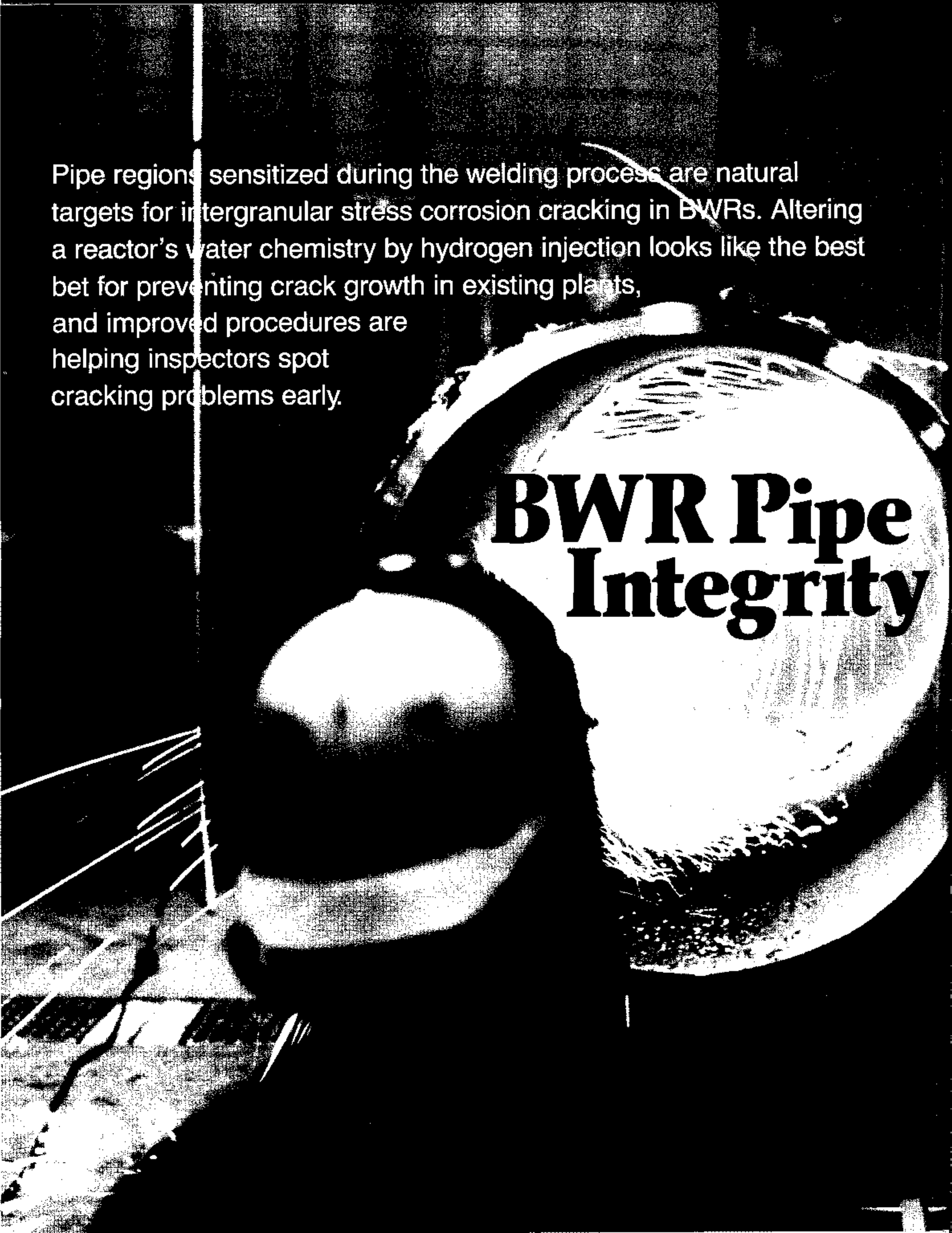
This article was written by Nadine Lihach. Technical background information was provided by Arnold Fickett and Edward Gillis, Energy Management and Utilization Division.

BWR Pipe Integrity

Pipe regions sensitized during the welding process are natural targets for intergranular stress corrosion cracking in BWRs. Altering a reactor's water chemistry by hydrogen injection looks like the best bet for preventing crack growth in existing plants, and improved procedures are helping inspectors spot cracking problems early.



The problem is microscopic: between the tiny grains of metal in one of the hundreds of pipes that carry water through a nuclear reactor, a crack appears and slowly begins to spread. Although none of the affected pipes has ever burst or endangered the public as a result, such fracturing—called intergranular stress corrosion cracking (IGSCC)—has had a serious economic impact on utilities that own boiling water reactors (BWRs). During the last decade more than 650 cases of IGSCC have been found in increasingly larger pipes, and efforts to prevent its spread have already cost utilities hundreds of millions of dollars. Now, as a result of intensive research, the cracking problem has finally been contained, although not completely eradicated.

EPRI and the Boiling Water Reactor Owners Group have played a leading role in this successful research program. To help detect IGSCC, EPRI's Nondestructive Evaluation (NDE) Center evaluated new inspection instruments and developed training methods for in-service inspectors. The center now offers advanced courses on how to detect cracks and determine their size, and its facilities are being used to test a variety of advanced instruments that can help automate inspection and thus minimize the exposure of personnel to radiation.

Several ways have [illegible] been found to prevent further damage in currently operating BWRs. Particularly important is the discovery that reducing the oxygen content and increasing the purity of water circulating through a reactor's pipes can both halt the growth of existing cracks and keep new ones from starting. Long-term verification of the effectiveness of this alternative water chemistry approach is now under way. Where severe cracking has already occurred, [illegible] methods have been developed to strengthen existing pipes or to replace them with more crack-resistant materials.

IGSCC will continue to be a major expense for many utilities as more inspections are conducted and new preventive measures are put in place. Changing the water chemistry at a plant, for example, may cost \$2 million, and installing new pipes typically runs \$50–\$60 million, not counting the cost of replacement power. Nevertheless, the price of IGSCC would have been far greater if suitable countermeasures had not been produced so quickly by the coordinated response of EPRI, General Electric Co., and the affected utilities.

History of the problem

The coolant system pipes of a BWR are made of austenitic stainless steel, which is ordinarily quite resistant to corrosion and cracking. For this reason engineers believed that the first detected occurrence of IGSCC, at Commonwealth Edison Co.'s Dresd[illegible] BWR in 1963, represented only a[illegible] incident. It was not until 1974 that the generic nature of the problem b[illegible] clear, when numerous cracks we[illegible] near welds in 4- and 10-in[illegible] several BWRs. The following [illegible] BWRs were shut down for inspection of their most susceptible welds, and when extensive cracking was found, the Nuclear Regulatory Commission (NRC) ordered more frequent inspection of the reactors once they returned to service.

Unfortunately, IGSCC is much harder to detect than the more common type of cracking, which is caused by metal fatigue. With IGSCC the cracks are thin and irregular, and their end points highly branched; this causes indistinct signals in ultrasonic testing equipment. Also, since cracking occurs most frequently near welds, signals from IGSCC often get mixed up with those from the bottom part, or root, of a weld. Because of this difficulty and the slow growth of the cracks, IGSCC was not discovered in large-diameter austenitic stainless steel pipes until 1978.

By 1982 extensive cracking had been found in a variety of large reactor pipes, ranging up to 28 inches in diameter and distributed throughout the cooling system. Clearly no pipe could any longer be considered immune.

In response NRC ordered all BWR owners to inspect their recirculation systems completely at the next scheduled shutdown and also required all inspection teams to demonstrate the effectiveness of their test procedures. EPRI worked closely with NRC to provide facilities at Battelle, Columbus Laboratories for these demonstrations. On the basis of this experience, in 1983 NRC issued updated requirements for capability demonstrations for reactor inspection. These demonstrations are now carried out at the EPRI NDE Center.

As the severity of the IGSCC problem gradually became apparent, research on its causes and possible remedies accelerated. Much of the early information about the nature of stress corrosion cracking came from work sponsored by EPRI and conducted by General Electric Co., which designed the BWRs. In 1979 the BWR Owners Group was formed to sponsor further research jointly with EPRI. In its first four-year funding cycle (1980–1983), the group comprised 22 utilities in the United States and 10 from abroad. During that cycle it contributed $30 million to the joint program, and EPRI contributed another $23 million. A second funding cycle has now begun and will extend through 1986. So far 19 U.S. utilities, 3 foreign utilities, and 5 nonutility members make up the current owners group; 3 additional foreign utilities are likely to join. Plans call for EPRI and the BWR Owners Group to contribute $13 million each to the current program, which is being coordinated with related research by NRC and DOE.

"EPRI's budget is limited enough that we couldn't possibly have addressed all the important questions in the depth they have now been covered," says Joseph Danko, senior program manager in the Nuclear Power Division and EPRI's liaison with the BWR Owners Group. "The resources provided by the owners group have been extremely important for the timely resolution of the IGSCC problem."

An insidious process

Out of this intensive effort has emerged a fairly clear picture of how cracking occurs. The process is an insidious one, and for it to occur three conditions must be met. The first is sensitization of the steel microstructure. Ordinarily stainless steel is composed of tiny grains that contain about 18% chromium, which makes them resistant to corrosion. When stainless steel is heated to 400–800°C, however—a condition that occurs repeatedly during the welding process—the chromium atoms combine with carbon atoms in the steel to form chromium carbide. This compound precipitates at the grain boundaries, causing them to become more susceptible to corrosion. The critical temperature range is reached in a heat-affected zone (HAZ) that extends about 0.25 inch (0.64 cm) on either side of a weld. It is in this region that most cracking occurs.

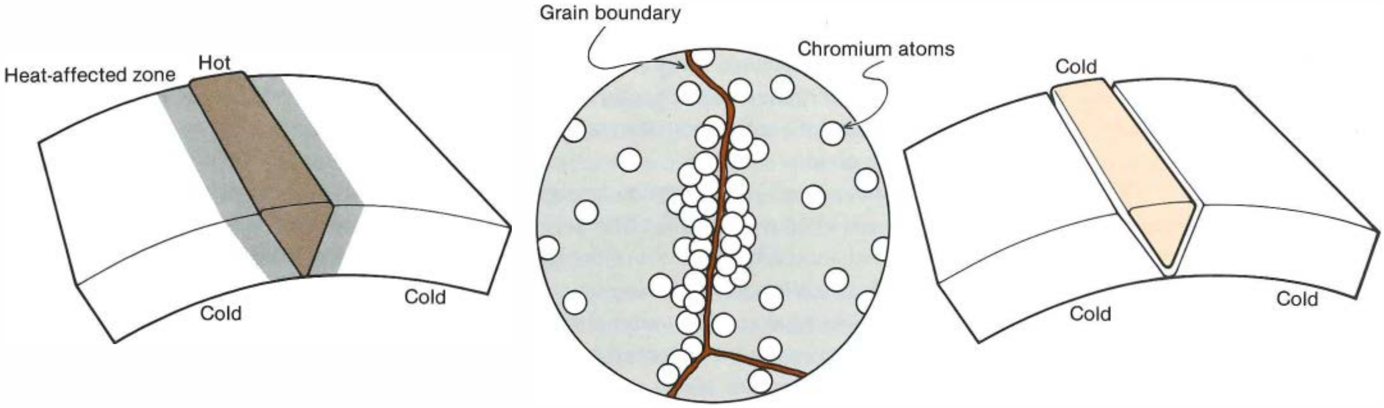
The second condition necessary in order for IGSCC to take place is tensile (stretching) stress on the sensitized area. Such stress can be caused by an external push or pull on the pipe, but the predominant contribution results from an internal condition caused by welding or machining. As a weld cools it contracts, which creates tension in the surrounding steel. Grinding or bending the pipe can also leave residual stresses inside the metal. Apparently such stresses break the thin protective film that forms on the inside of a pipe after it first comes in contact with water. Through this process the intergranular stress corrosion cracking is initiated. This microscopic cracking allows oxygen to diffuse into the spaces between sensitized grains of steel, which results in further corrosion and crack propagation.

The third necessary condition for IGSCC is thus the presence of a certain amount of oxygen, but determining how much oxygen is enough to cause problems can be difficult. In general, keeping the amount of oxygen in the cooling water below 20 parts per billion (ppb) is sufficient to inhibit IGSCC, but the exact level depends on the conductivity of the water, which in turn depends on its purity. In other words, the corrosion potential (or electrochemical potential) of the water depends on both oxygen content and impurities. Electrochemical potential is measured in millivolts (mV) and can be thought of as the driving force behind IGSCC. To prevent crack formation in BWR stainless steel, the electrochemical potential in the cooling water has to be kept below (more negative than) about −350 mV. Under normal conditions the electrochemical potential of BWR water is around −150 mV, hence the problem of stress corrosion cracking.

Reducing the damage

Eliminating any one of the three necessary conditions can halt the IGSCC process. In newly constructed plants sensitization can be avoided by using nuclear grade stainless steels, which contain very little carbon and thus are not as susceptible as conventional stainless steels to chromium precipitation. However, carbon adds to the strength of a steel, so nuclear grade metals must contain additional nitrogen to compensate. Under some conditions nitrogen-based steels are susceptible to a related fracturing process—transgranular stress corrosion cracking—but cracks caused by that process tend to grow much more slowly than those caused by IGSCC and are of no

Cracking develops not in the weld itself but in the heat-affected zone that extends about a quarter inch on either side. Under the heat of the welding process, the chromium atoms that normally make stainless steel corrosion-resistant migrate to the metal's grain boundaries and form chromium carbide; as a result, the alloy's resistance to IGSCC is reduced. Tensile stresses are created when the weld cools and contracts slightly, allowing oxygen to diffuse between the boundaries and further facilitate cracking.



engineering significance in BWRs.

New ways have been found to relieve the tensile stresses near welds that contribute to pipe cracking. For fresh welds cold water can be applied to the internal surface of a pipe, either during the entire welding process or just during the last welding pass. This procedure—called heat-sink welding or last-pass heat-sink welding—cools the surface and creates a compressive stress that tends to inhibit cracking. The principle behind the procedure can be modified for application to existing welds. Called induction heating stress improvement (IHSI), this latter technique entails heating the outside of a weld to about 550°C while keeping the internal surface at about 150°C by means of flowing water. IHSI has been used extensively in Japan and at some U.S. plants, but its application does not guarantee immunity to IGSCC and can involve radiation exposure to workers.

Where IGSCC damage is extensive, the integrity of a pipe can be reinforced by overlaying the cracked region with a continuous band of weld metal several inches wide and two to five layers deep. This band consists of low-carbon austenitic stainless steel, which is very resistant to IGSCC, and it is applied by using heat-sink techniques that produce compressive stresses. So far NRC has approved the use of such weld overlays only as a temporary measure to carry a plant through one fuel cycle, but two pipe-test programs are under way to determine whether the technique might also be used to mitigate the effects of IGSCC over longer periods.

Alternative water chemistry

Because of the difficulties and expense of replacing pipes or modifying welds, probably the best hope for preventing further IGSCC in existing BWR plants lies in changing the electrochemical potential that drives the process. This change can be made by adopting an alternative water chemistry that features both lower oxygen content and greater purity to reduce conductivity.

When a reactor is shut down and open to the air, the dissolved-oxygen content of its water may rise to as much as 8000 ppb. Most of this oxygen, together with other gases, is driven off during startup, but then radiation begins breaking down water molecules to produce hydrogen and oxygen. At steady state the oxygen content is about 200 ppb, roughly 10 times the level considered safe for preventing IGSCC.

At first it was hoped that reducing the very high levels of oxygen present during startup might substantially reduce IGSCC, but tests showed that such a procedure would have only limited value. Although startup deaeration may prove useful during the initial shakedown period (when stresses are especially high), steady-state oxygen levels clearly must be kept well below the levels previously tolerated. Various oxygen-suppressing additives were considered during a program begun in 1977 by DOE. This study indicated that the addition of hydrogen—which combines with the excess oxygen to form water—would be most effective.

In 1982 in a joint effort by EPRI, DOE, General Electric, and Commonwealth Edison, a one-month test of this hydrogen water chemistry concept was conducted at the Dresden-2 BWR in Morris, Illinois. Hydrogen was added to the feedwater at the rate of 1.5 ppm, which reduced the oxygen content of the reactor's cooling water to the desired level of 20 ppb. This test successfully demonstrated the feasibility of using hydrogen addition and augmented water purification to suppress IGSCC, and a long-term verification program was begun at Dresden-2 in April 1983, with funding from EPRI, General Electric, and Commonwealth Edison.

Because BWRs already have extensive water cleanup systems, the importance of extra purification came as something of a surprise to researchers. Only tiny amounts of chloride and sulfur ions enter the water stream from leaking condenser tubes or from the breakdown of resins used in the cleanup system itself. But these ions carry enough electrical charges to enable corrosion to take place even with very little oxygen present. The ability of electrical charges to flow through a substance is called conductivity and is measured in microsiemens per centimeter (μS/cm). NRC currently recommends that conductivity in BWRs be kept below 1 μS/cm, a very low level. With additional purification, however, the conductivity at Dresden-2 is being kept at less than 0.2 μS/cm. At that level the electrochemical potential of the water can be maintained at about -450 mV, well below the corrosion threshold.

Fortunately, laboratory studies have shown that even severe temporary excursions from ideal water conditions will not necessarily restart the IGSCC process. A stainless steel corrosion film exhibits a memory effect; that is, it does not react to increased levels of oxygen and higher electrochemical potential for up to 10 hours. Therefore, the hydrogen injection system can be shut off periodically for inspection and maintenance.

Verification issues

Not only is the long-term verification program at Dresden-2 providing operating experience with alternative water chemistry—the plant's hydrogen injection system is currently operating at about 95% availability—it is also addressing two critical issues. First, engineers must make sure that adding hydrogen to the cooling water will not damage the Zircaloy cladding on fuel rods. Under some circumstances hydrogen can react with Zircaloy to form zirconium hydride, which is brittle and hence could make fuel rods more susceptible to damage during the handling required to change fuel assemblies. The possibility that such damage might occur has so far prevented the extension of fuel warranties to BWRs that use alternative water chemistry.

Nonetheless, hydrogen embrittlement—as it is called—is not really expected, because experience with higher levels of hydrogen in pressurized water reactors has shown that hydrogen pickup can occur without causing damage to fuel rods. Definitive answers will probably be provided this fall when Dresden-2 is shut down for refueling. (Further tests of the whole alternative water chemistry system are planned for the next 18-month cycle at the plant.)

The second major issue being addressed during the verification program is what should be done about the higher levels of radioactivity that occur around a plant using alternative water chemistry. As hydrogen is added, oxygen is neutralized and otherwise stable nitrates in the water are broken up to form gaseous nitrogen. This gas first circulates along with steam through a plant's turbines and then is released into the air. A small proportion of the nitrogen is radioactive N-16, which emits gamma rays and has a half-life of about 7 seconds.

Because of this additional N-16, the radiation levels around a plant's steam lines and turbines—sometimes called turbine shine—increase roughly fivefold with the change to alternative water chemistry. Radioactivity outside the turbine building also increases substantially because of off-gassing. Since N-16 has such a short half-life, radioactivity in the affected buildings drops off quickly when the hydrogen system is shut down, and employee exposure can be minimized. Also, since the turbine building at Dresden-2 is well shielded and favorably located, increased radioactivity at the site boundary is negligible. Other plants, however, may have to add shielding or make other adjustments; thus EPRI is recommending short-duration tests with extensive radiation monitoring at sites where alternative water chemistry is being considered.

In addition to these two long-term issues, a more limited operational difficulty has arisen at Dresden-2 with the addition of hydrogen to the cooling water. Because of the plant's design, small fires occasionally break out inside the pipes that expel gases from the reactor system. The addition of hydrogen has aggravated this existing problem, and off-gas fires have been the major cause of shutdowns of the alternative water chemistry system during tests at Dresden-2. The fires appear to result from the unique pipe configuration at Dresden-2, however, so this difficulty is not expected to occur elsewhere. Modifications to the Dresden-2 system to eliminate this problem are planned for the plant's scheduled outage this fall.

"Technology is now in place for long-term resolution of the IGSCC problem," according to Adrian Roberts, senior program manager for the Nuclear Power Division's Fuels and Materials Program. "Utilities can now choose from a number of different remedies—new nuclear grade pipe, stress relief welding and overlays, and, in a short time, a qualified alternative water chemistry. We believe the verification program at Dresden-2 is going quite well, so next we want to concentrate on reducing the cost of hydrogen addition and providing better ways to monitor the water chemistry."

The crucial role of inspection

Knowing which of the available remedies to apply in particular circumstances depends on being able to detect IGSCC and measure how far cracks have spread. The most commonly used technique in such inspections entails transmitting very high frequency sound into a pipe and then studying the reflecting vibration patterns—a technique somewhat like sonar. However, some difficulty in applying ultrasonic inspection to IGSCC was experienced in 1982 when repairs were being made on Niagara Mohawk Power Corp.'s Nine Mile Point-1 BWR. At that time inspectors found previously undetected cracking in piping in the recirculation system.

As a result of this discovery, NRC ordered new inspections of large pipes at nine BWRs and also required all inspection teams to demonstrate the effectiveness of their techniques. In less than two weeks, these demonstrations were organized by EPRI through the NDE Center and were conducted at Battelle, Columbus Laboratories, where radioactive test specimens from Nine Mile Point-1 could be handled. When several of the inspection teams had difficulty finding all the cracks in the test specimens, the NDE Center organized a workshop to provide specialized training in the use of ultrasonic equipment for IGSCC detection and characterization. Because of this intensive effort, all the plants affected by this initial NRC bulletin were able to comply quickly.

To provide for long-term upgrading of inspections, in 1983 NRC issued a second bulletin, which defined inspection demonstrations more formally and required new inspections at 15 more BWR plants. To handle these ongoing proficiency demonstrations, EPRI provided a new facility at the NDE Center capable of handling radioactive samples. The center also organized a five-day training program for IGSCC detection, which entails extensive laboratory work as well as hands-on exercises.

Already the course has trained more than 260 students and has helped ease a manpower shortage that began to develop when previously qualified inspection teams reached their permissible levels of radiation exposure. Rather than requiring a separate test, NRC now accepts the results of the practical examination given at the end of this course as an adequate demonstration of proficiency.

Determining crack size

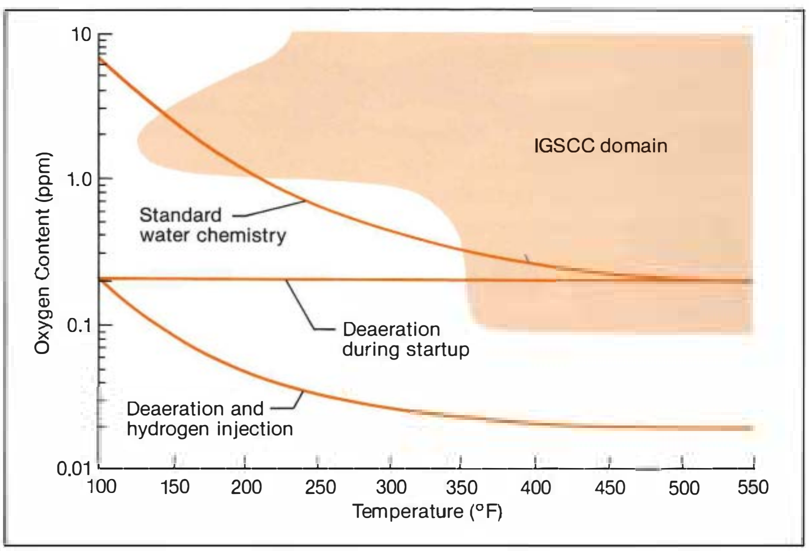
After the discovery of cracks in large pipes, NRC was concerned with upgrading methods of detecting IGSCC. The affected utilities, however, also wanted to make sure that ultrasonic inspection could be used for sizing the cracks once they were found. Choosing the right sort of remedy for a particular pipe depends on being able to determine the sizes of cracks within it.

In May 1983 several utilities asked EPRI to conduct a round-robin sizing exercise in which teams of inspectors would use various techniques to measure the extent of cracking in 12 pipes. A total of 14 teams from vendors and utilities took part, and some automated systems were also tested. After the ultrasonic inspections had been completed, the samples were sectioned to confirm the exact extent of cracking. The results indicated that the ability of individual inspectors to size cracks by manual techniques needed improvement. The automated systems generally did better than their human counterparts.

The exercise was not intended as a qualification program but rather as a test of the current state of the art. The EPRI examiners concluded, however, that ultrasonic techniques could indeed be used to size IGSCC. EPRI recommended that a new training program be set up to acquaint inspectors with the best sizing techniques and that the development of automated systems be accelerated.

The proposed training program has now been established at the NDE Center, and more than 60 people have taken the four-day course so far. Several ultrasonic techniques are taught, and participants learn how these methods complement each other in the process of determining crack size. Although the NDE course in crack detection is not a prerequisite, it is highly recommended for individuals who have not had considerable field experience in IGSCC inspection.

Temperature and dissolved oxygen in the reactor water define a domain of operation in which BWR pipes are susceptible to IGSCC. Although deaeration makes it possible to avoid this domain at startup temperatures, it is ineffective when high, steady-state operating temperatures are reached. A combination of deaeration and hydrogen injection lowers the water's oxygen content enough so that the IGSCC domain is skirted entirely and susceptibility to cracking is avoided.



"The utility industry has taken the initiative to improve inspection standards," says Gary Dau, senior program manager for the Nuclear Power Division's Structural Integrity Program. "The training programs we have set up are helping build a cadre of qualified inspectors. But it's like issuing a driver's license—you don't know how well people will actually drive on the road. Our next step is to verify the adequacy of inspectors' field performance. Data gathered so far indicate they are performing satisfactorily."

Advanced approaches to inspection

New technology will improve IGSCC inspection by helping automate both data collection and analysis. The judicious use of such automation can decrease the exposure of inspectors to radiation, provide a permanent record for tracking crack growth, and make IGSCC detection less ambiguous. EPRI is sponsoring the development of several technologically advanced approaches to inspection, which are then submitted to the NDE Center for the qualification testing specified by NRC.

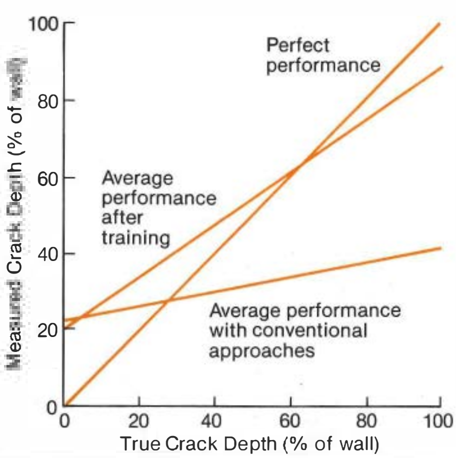
Two basic methods are being used to analyze ultrasonic signals and discriminate characteristic patterns of IGSCC. Feature-based analysis examines the time and frequency distribution of a single reflected signal and compares the findings with features known to characterize the type of cracks being sought. Such an analysis is virtually instantaneous and can be used by an inspector as he manually scans a pipe. Image-based analysis provides an inspector with a cross-sectional picture of a pipe based on a series of consecutive signals produced by automated scanning. The image is constructed by computer and displayed on a color monitor.

The ALN 4060 Flaw Discriminator is a feature-based analyzer that can be used either manually or as part of a fully automated inspection system. Developed for EPRI by General Research Corp., this instrument can be trained to discriminate up to three classes of signals—for example, those from IGSCC or those from a weld root. Training consists of exposing the instrument to a particular class of signal and calculating up to 42 features that characterize the signature of that class. A microprocessor within the instrument then formulates an algorithm based on the three or four features that will best allow it to discriminate that class from other classes on the basis of signature. Two vendors have purchased the ALN 4060 to help make manual inspection more reliable.

Another key element needed to build an integrated inspection system is an automated pipe scanner. Several integrated systems now use the track-mounted AMAPS scanner, developed for EPRI by Amdata Systems, Inc. This scanner consists of a flexible track that wraps around a pipe, a mechanical system that moves along the track and is held to it by permanent magnets, and a small search unit that holds a transducer for sending and receiving ultrasonic signals. More than 20 AMAPS units are currently in use.

The first fully automated ultrasonic pipe inspection system to pass a limited NRC qualification test is called CUDAPS. It uses the ALN 4060 Flaw Discriminator and the AMAPS pipe scanner together with a remote control unit and a microprocessor. CUDAPS was first assembled and tested by the NDE Center staff. Once installed on a pipe—initial installation takes less than 5 minutes—the unit can be completely controlled by an operator

EPRI's NDE Center has become the focal point for BWR pipe inspection training and the development of automated inspection systems. For example, new ultrasonic techniques and procedures being taught in one four-day course at the center have dramatically improved the accuracy of crack depth measurements; up to 16 people can take the training during each session.



INTERNATIONAL IGSCC EFFORTS

Intergranular stress corrosion cracking is an international problem that affects virtually all countries with BWRs based on the original American design. The principal exception involves Kraftwerk Union–designed BWRs in West Germany, which use a niobium-stabilized austenitic stainless steel (type 347) rather than type 304 or 316 austenitic stainless steels. The pipes in the German reactors have thus far appeared to be immune to the severe cracking that has affected BWRs elsewhere.

Through the Boiling Water Reactor Owners Group, EPRI is working with utilities in several countries to attack the IGSCC problem. Much of this activity is now focused on the hydrogen water chemistry approach.

Sweden has a particularly ambitious program, which involves using hydrogen water chemistry in several BWRs of different designs. EPRI is helping sponsor several joint projects with Swedish utilities. The objective of this research is to develop a data base from which to derive a model that can be used to design hydrogen water chemistry systems for all BWRs.

Japan has made use of a number of pipe remedies: induction heating stress improvement, which was developed in that country; corrosion-resistant cladding; and replacement of some pipes with low-carbon austenitic stainless steel. □

up to 200 feet away. The unit's motion is controlled by using either a keyboard or a joystick, and data are recorded automatically. All components that make up CUDAPS are now commercially available. This unit was used to gather ultrasonic data for field experiments at the Fitzpatrick power plant of the New York State Power Authority and the Hatch-2 unit of Georgia Power Co.

The Ultrasonic Data Recording and Processing System (UDRPS) is another automated instrument that has passed the limited qualification tests at the NDE Center. UDRPS was originally developed for Pacific Gas and Electric Co. by Dynacon Systems, Inc., and was subsequently evaluated and upgraded with EPRI funding. It has been used at the Millstone-1 plant of Northeast Utilities and at Niagara Mohawk's Nine Mile Point plant.

The first automated system to pass an unlimited NRC qualification test (on both pipes and safe-end joints) is called Intraspect, which uses an image-based analyzer with the AMAPS scanner. Developed for EPRI by Amdata, this system produces cross-sectional or planar views of the region in question, with cracks and other sharp reflection points clearly visible on a video monitor as glowing white regions in a field of dull red and orange. A complete scan of one side of a weld for a 12-inch pipe takes about 20 minutes, with cross-sectional resolution of 0.05 inch (0.13 cm). Intraspect has just become commercially available, at less than $100,000, and the first field demonstration was held in July at Georgia Power's Hatch-2.

"Fully automated inspection systems will significantly reduce unnecessary radiation exposure to inspection personnel, and they can be operated by less-skilled inspection personnel," says Soung-Nan Liu, project manager for nondestructive evaluation. "They can make IGSCC inspection results more repeatable and also available in a more understandable form. Our main task now is to work on the acceptability of these systems, because most inspectors are not yet familiar with their advantages."

Containing IGSCC

Clearly, the cost and trouble caused by IGSCC are far from over, but a powerful combination of new remedies and better inspection techniques has finally—in the word used by several researchers—contained the problem. This means several things. First, and by far most important, utilities can now be reasonably sure that pipe cracking does not pose a threat to safety. The IGSCC process is understood well enough that crack growth and its effect on pipe integrity can be predicted quite accurately. In particular, the concept of "leak before break"—meaning that even undetected cracks will not lead to pipe breaking without first signaling their presence by producing a leak—is now generally accepted.

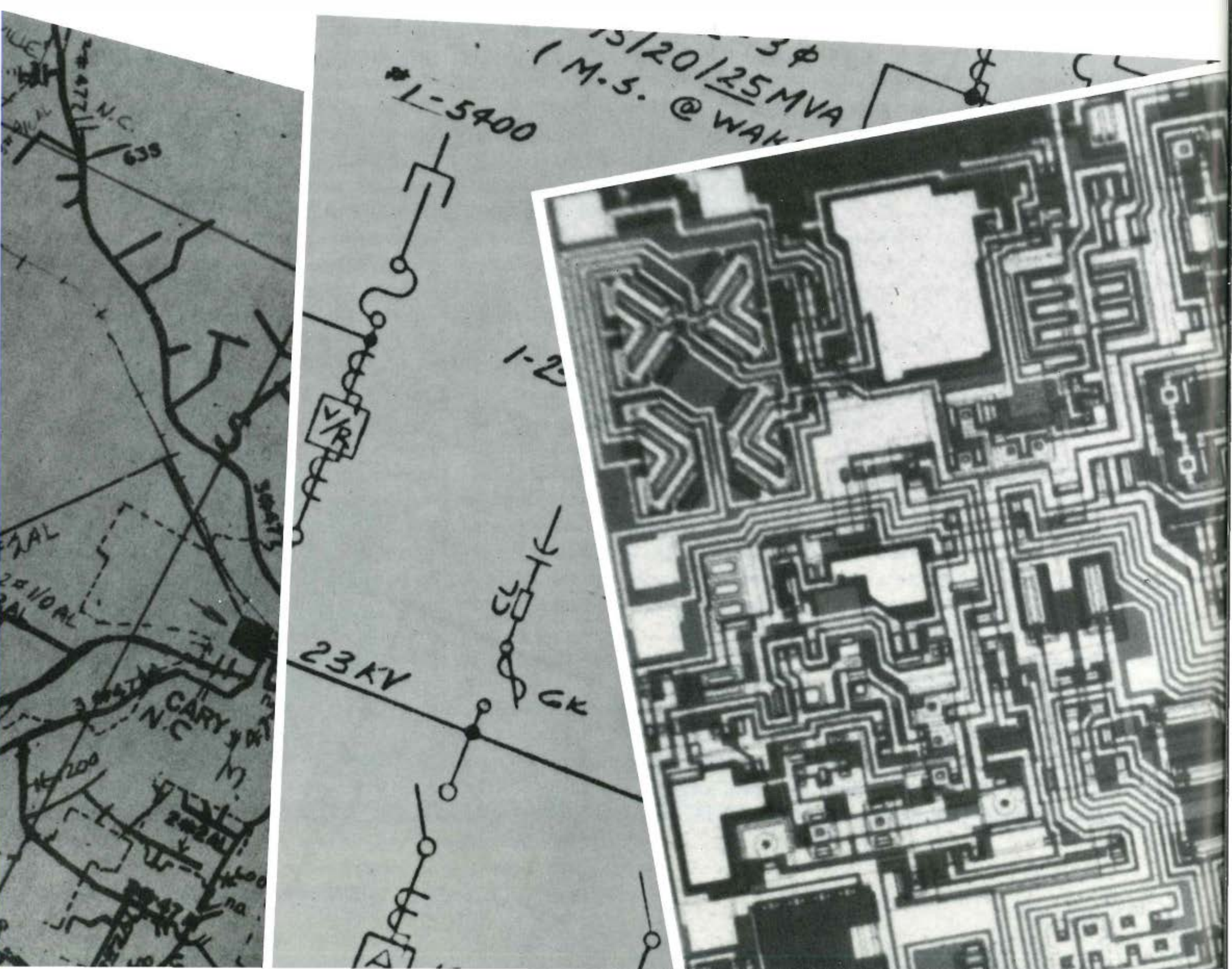
Containment of the problem also means that utilities can now prevent crack growth by using alternative water chemistry and that they can choose among several remedies when IGSCC does occur. Depending on the extent of cracking, pipes can be replaced with more resistant materials, stresses around welds can be reduced, or bands of welding material can be used to reinforce an affected area. Usually the choice among these remedies depends on the results of inspection. Despite the uncertainties involved in sizing, inspection techniques are now adequate for the task. Pipe integrity depends on the cross-sectional area affected by cracking, which is subject to much less uncertainty than linear crack measurements.

These accomplishments have come quickly because of intense industry action. The BWR Owners Group made major funding available so that the IGSCC problem could be tackled from many directions at once. EPRI coordinated this massive R&D program and provided the necessary facilities through its NDE Center. The benefits that have resulted from this cooperative effort are almost impossible to calculate. They can perhaps best be appreciated by considering the enormous costs that would now face BWR owners if the IGSCC problem had not been contained. ■

This article was written by John Douglas, science writer. Technical background information was provided by Joseph Danko, Adrian Roberts, Gary Dau, and Soung-Nan Liu, Nuclear Power Division.

The arrival of microelectronics and communications technology for power distribution systems promises a new era in the way utilities deliver electricity to customers. Automating many of the functions now performed by electromechanical switches and relays will improve reliability, reduce costs, and offer greater opportunities for conservation and load management.

Automating the Distribution Network

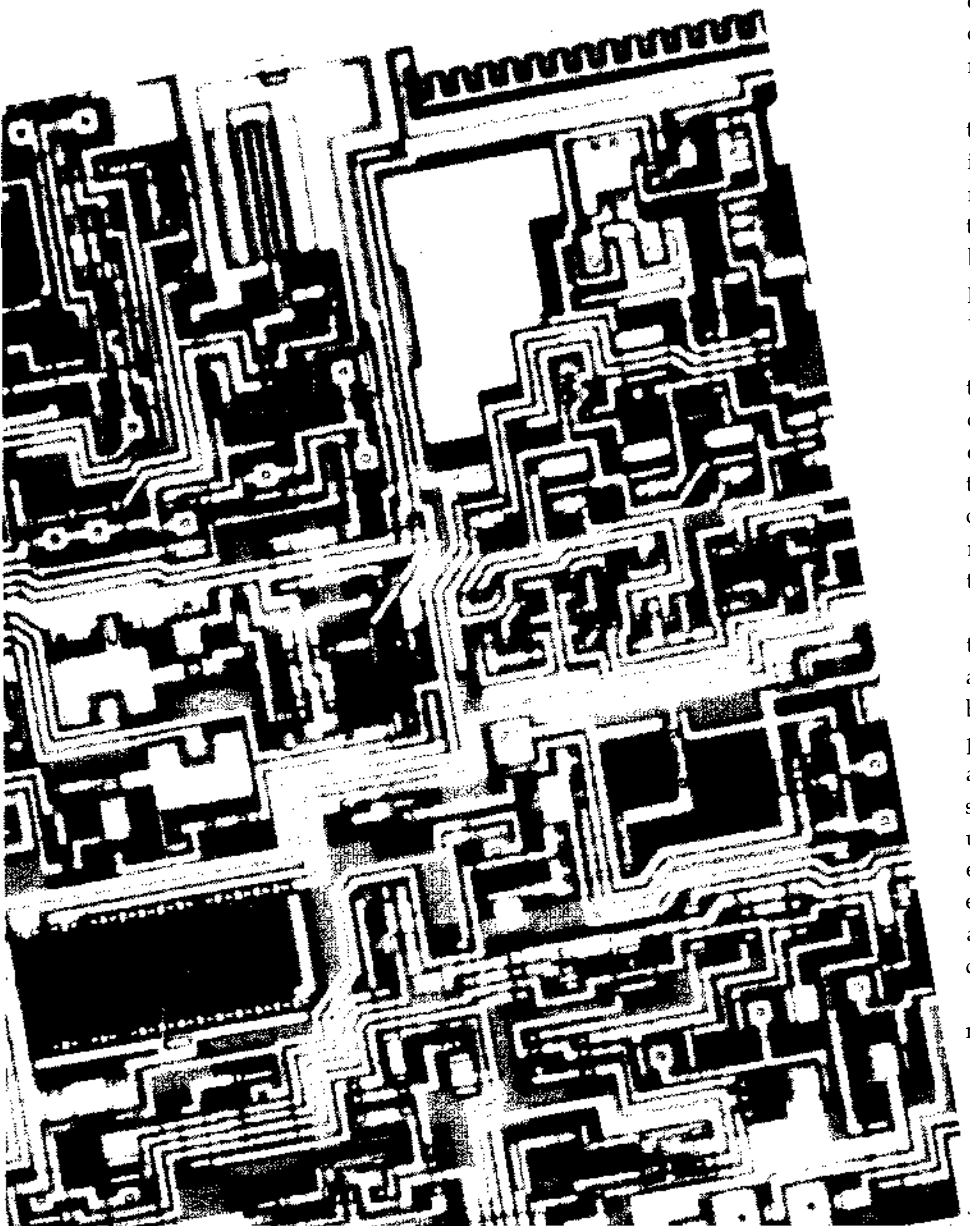


Thunderstorms can sometimes interrupt electric utility service to tens of thousands of customers by causing a tree branch to fall across a single distribution line. Typically, those customers may be without power for several hours until service crews arrive, search for the affected line, and isolate the fault. The nature of today's utility distribution systems makes the process of troubleshooting labor-intensive and time-consuming.

Likewise, the routine task of reading customer meters is costly in terms of personnel and time, typically keeping dozens of crews busy. In the extreme, in some urban service areas where two-person crews are required for safety, the cost can reach over $50 per meter per year—as much as 10 times the national average.

On another front, when high peak power demand from air conditioners threatens brownouts on hot summer days, utilities are sometimes forced to broadcast radio pleas for reduced electricity use to avoid overloading an already taxed power network.

Each of these situations relates to aspects of the principal point of interaction between customers and a utility: the distribution system—the network of lines, transformers, and switches that crisscrosses cities and neighborhoods, reaching into nearly every place where people live and work in this country. And technological change is hastening the day when each situation will be characterized much differently.



Utilities will electronically sense storm-related faults on distribution lines and reroute power automatically to minimize the number of customers affected and reduce the time to restore service to others. Meter reading will become an archaic phrase; the job will be performed automatically and more accurately by computer. And when a utility has to limit peak demand, it will be able to send electronic commands to its customers' air conditioners and other energy-intensive equipment, causing them to cycle off and on and thereby lowering the total demand on the system.

This thumbnail sketch is only part of the change that will come from automating today's distribution networks with microelectronics and communications technology. Most of the change will not be apparent to utility customers, but it promises to significantly alter the way utilities now distribute electricity.

Most of the common distribution activities now handled by electromechanical devices with assistance from utility engineers—such as switching, fault detection, feeder loading, and capacitor bank control—will be performed invisibly by microprocessors as a technician monitors the work from a computer terminal.

Distribution automation will also open the door to new capabilities in load management, the control of customer loads by a utility in order to flatten the sharp peaks in power demand that can result at certain times and in unusual circumstances. Load management can give a utility the flexibility to defer new generating plants, transmission facilities, and even new distribution facilities, as well as avoid overload conditions during peak demand periods.

All the benefits of distribution automation add up to greater reliability for customers, more economical use of resources for utilities—including capital for new facilities—and a degree of control and protection never before available to utility distribution engineers. "The benefits of distribution automation filter through the whole operation of an electric utility," notes John Dougherty, vice president for EPRI's Electrical Systems Division. "Everybody wants it because, potentially, everybody wins."

A new dimension

More than 40 distinct functions, ranging from voltage control to meter reading, come under the heading of operations that can be performed electronically with distribution automation. Digital data processing and communications add a new dimension to utility operations that represents a major step toward true integration and coordination of power generation, transmission, and distribution.

"An automated distribution system will be capable of doing a lot of different things," says Dougherty, "and in exploring these possibilities, it's becoming clear that if a utility can use as few as two of the more important functions, such as more efficient transformer loading and detection of energy theft, it can probably afford to automate its distribution system. If a utility takes advantage of all the benefits, distribution automation becomes very cost-effective. In fact, it could be a real money-maker in the long run."

As more utilities adopt load management strategies as a means of deferring investment for peak generating capacity, so are more utilities exploring the benefits to be gained from automating distribution systems. A 1980 EPRI survey of utility load management projects found 72 new programs over the previous year for testing and evaluating a variety of communications systems for distribution automation.

Much of the technology required to automate a power distribution system has only recently become available at a price that warrants serious consideration of its application. The cost of microprocessors, which are at the heart of both the communications equipment and the computers required for distribution automation, has fallen dramatically in recent years. Installed costs of distribution automation technology are approaching \$100–\$150 per customer control point.

The challenge now is to devise sophisticated software, or operating instructions, that can effectively tap this computing power to perform the diverse but repetitive tasks involved in power distribution, according to William Blair, project manager in the Electrical Systems Division's Distribution Program.

"Most of the major projects in this area will focus on software in the future," says Blair. "Reliable hardware is now becoming available. We now have communications and data processing hardware that is versatile enough to cope with the drastic changes in system configuration that would be experienced in distribution automation. Software now has to catch up."

One of the major hurdles in developing distribution automation systems was communications. To perform many of the functions of automated distribution, utilities must have a means of transmitting commands to various control points along the distribution lines. Some functions, such as remote meter reading and status monitoring, require two-way communication. Although this capability has been technically within reach for some time, it is only recently that the cost of such systems has made their use for distribution automation economically attractive.

An early goal of distribution automation research was to demonstrate that communications technology could be applied to distribution with a high level of performance and reliability. EPRI and the Department of Energy supported the demonstration of three prototype distribution communications technologies in the late 1970s: power line carrier (PLC) systems, radio-based systems, and telephone line–based systems.

What differentiates the three is the medium by which control signals are sent and received. PLC systems use existing 60-Hz utility power lines to carry digital data impulses that a computer or microprocessor can translate to commands and information. Radio systems use VHF or UHF bands as the communications link; a telephone-type system employs conventional or leased lines.

Three PLC systems have been tested on utility distribution networks: one developed by American Science and Engineering, Inc., was installed at San Diego Gas & Electric Co. under DOE sponsorship; EPRI supported tests at Carolina Power & Light Co. of a PLC version produced by Brown Boveri Compugard Corp.; and a Westinghouse Electric Corp. PLC system was tested at Detroit Edison Co.

A UHF radio system, also developed by Westinghouse, was installed and tested on Long Island Lighting Co.'s system, and a telephone communications system produced by Harris-Darcom, Inc., was evaluated on the Omaha (Nebraska) Public Power District and Metropolitan Utility District systems in cooperation with Northwestern Bell.

Each of these communications systems provided for two-way communication to approximately 700 customer meters and 50 distribution control points; each was operated and tested by the utilities for approximately one year. Over 2 million separate two-way communications operations were logged.

"Although the systems did not perform at levels predicted by the manufacturers at the beginning of the program," notes Blair, "some performed well enough to validate the concept of distribution communications." One conclusion of the work was that a large utility distribution automation project may use all three of the techniques to meet different operational needs in different parts of the service territory.

On the simple basis of communications reliability, the telephone system performed better than the other communications systems, as was expected. Institutional problems, however, will probably preclude the use of telephone systems for large-scale distribution automation for the foreseeable future. These issues include utility access to telephone subscriber circuits, the determination of cost-effective tariffs for utility use of those circuits, and organizational questions raised by the breakup of the American Telephone & Telegraph Co. system.

Power line carrier

The most commercially promising of the systems tested is the Westinghouse PLC system. On the basis of its initial performance, which featured a communications success rate of about 85%, this system is considered the most likely to perform, with improved hardware and software, at the 95% or better level needed to satisfy utility data communications requirements. In a follow-on project, the 100 worst-performing meter/control points from the original effort were used to verify improved performance. The system performed successfully before and after a distribution test feeder was sectionalized, or switched into a different configuration.

At least five distribution equipment vendors, including Westinghouse, are now commercializing PLC-type systems. Some of these systems, including the Westinghouse equipment, are asynchronous, which means that they do not depend on the 60-Hz utility power frequency to operate; thus communications between control points can be maintained even if the power lines are dead. This satisfies an important criterion for distribution communications: the communications equipment must continue to function following a line fault or major outage.

To demonstrate the Westinghouse PLC system at a scale sufficiently large to confirm its readiness for commercial use, EPRI plans to conduct a 5000-point test of a prototype at Carolina Power & Light Co. The functions to be demonstrated will include electronic meter reading and equipment monitoring; remote load surveying; feeder and substation automation, including digital control and protection interfaced with the utility's supervisory control and data acquisition (SCADA) system; and computerized distribution dispatch and control.

Equipment development and implementation are expected during 1985, with most of the testing to come in 1986. Results could become available in 1987, adds Blair. Beyond that, EPRI and Carolina Power & Light are planning to make the system available for load management demonstrations and studies.

To encourage equipment compatibility, Westinghouse plans to make its system capable of intertying with two sister substations with digital distribution control and protection systems manufactured by General Electric Co. and McGraw-Edison Co., respectively. In addition, Energy & Control Consultants, Inc., will define the interface requirements between the generic subsystems, for the interties between distribution substations equipped with different systems, and for differential relaying between the utility transmission and distribution systems.

Radio links

A communications technology equally as promising as PLC systems is the use of radio signals to carry utility data and com-

CURRENT EPRI DISTRIBUTION AUTOMATION PROJECTS

Title and Number	Contractor and Host Utility	Funding ($000)	Period of Performance
Distribution automation and load control system (RP2592-1, -2)	Westinghouse Electric Corp., Carolina Power & Light Co.	7643	6/84–6/88
Interface requirements for distribution automation and load control (RP2592-3)	Energy & Control Consultants, Inc.	195	6/84–6/85
Integrated control and protection of distribution substations and systems (RP1472-1)	General Electric Co., Texas Electric Service Co.	4574	5/79–12/85
Broadcast radio system for distribution automation (RP1535-3, -4)	McGraw-Edison Co., Philadelphia Electric Co.	2503	8/81–12/85
Measurement of electrical noise and harmonics on utility systems (RP2017-1)	SRI International	1263	8/81–12/84
Communications systems for distribution automation (RP850-32, -33)	Westinghouse Electric Corp., Detroit Edison Co.	538	8/82–9/84
Economic evaluation of distribution automation (RP2021-1)	General Electric Co., Public Service Electric & Gas Co.	271	7/82–9/84

mands. Radio systems have two unique advantages: data can be retrieved from random, scattered points around a utility service territory, and the systems can communicate point to point over long distances at high data rates, allowing many control and metering points to be polled for data simultaneously. PLC signals must be implemented in an entire substation region to be cost-effective and cannot retrieve data from many points at once.

EPRI first studied the feasibility of a broadcast radio system for distribution communications in 1982. A two-way AM/VHF system manufactured by McGraw-Edison's Electronic Products Division (formerly Altran Electronics, Inc.) was tested on Southern California Edison Co.'s system in the Los Angeles area.

The radio system employed a phase-modulated (PM) digital control signal superimposed on the existing commercial AM broadcast signal of radio station KNX for the forward (command) link; the return (data) link involved a low-power narrow-band VHF or UHF transmitter at each control point tuned to a central receiver. The VHF/UHF transmitters and central receivers were synchronized with the AM broadcast signal. "This rather clever concept significantly reduces the cost of the remote transmitters, increases data transmission rates, and improves reliability over conventional VHF/UHF two-way communications systems," notes Blair.

Altran Electronics manufactured 50 prototype devices for this six-month test. The forward link was tested over a range of up to 200 km (120 mi) with a communications success rate exceeding 98%. The prototype VHF return link was tested at 10 points over a range of up to 30 km (18 mi) with a success rate of over 90%.

Southern California Edison and Altran concluded that the AM broadcast signal was ideal for transmitting digital PM signals; no interference was detected between KNX programming and the digital load management signals. Because the broadcast system's performance exceeded expectations, EPRI has funded a 1000-point demonstration of the broadcast communications system at Philadelphia Electric Co.

This follow-on project will evaluate the radio system's performance in a severe radio noise environment, such as that found in the Philadelphia–New York metropolitan area. Plans call for 500 one-way communications points and 500 two-way points. Equipment for this project is now being installed, with testing scheduled for 1985; final reports are expected the following year.

The higher-frequency, less-crowded UHF radio band may be the more promising for radio-based distribution communications. Many utilities already use VHF equipment for some distribution automation functions, but VHF-based systems have a maximum capacity of about 5000 control points. For large-scale distribution automation, the available UHF frequencies with sufficient bandwidth are in the 940–952-MHz range, which has been recently set aside by the Federal Communications Commission for use by electric utilities.

Control and protection

Communications systems would give utilities new opportunities in the control and protection of distribution systems and substations. Computer-based control systems would link automation at the distribution line level with the distribution dispatch center; these systems could sense the status of various control points and react with commands (e.g., to sectionalize a feeder) more efficiently and intelligently than is now possible with conventional electromechanical relays.

An engineering prototype of such an integrated control and protection system is being installed at Texas Electric Service Co.'s Handley substation near Fort Worth. Field trials of the system, manufactured by General Electric, will be carried out next year. The substation is served by two 138-kV buses from the adjacent Handley generating station; three 22.4-MVA, 138-kV/12.5-kV transformers supply three stations of 15-kV metal-clad switchgear and six 12.5-kV feeders.

General Electric's control and protection system is designed to overlie, but not override, the electromechanical control system; it is also designed to operate independently of the type of communications system that couples it to distribution line control points. According to Thomas Kendrew, project manager, an important feature of the system's protection module is its capability of operating in a stand-alone mode. "If the data acquisition system is down, if everything else in the substation is down, the protection module will continue to function; it even has a backup system. This is something a distribution system has never had before," explains Kendrew, "because with conventional systems, you couldn't afford redundant protection."

The heart of the integrated system is the substation integration module, the hardware for which is built around Intel 8086 advanced microprocessors configured in a distributed architecture. The module collects data from three other subsystems and maintains a real-time data base for substation and feeder control.

The integration module also maintains the communications interface with the distribution dispatch center and the utility SCADA system, and if desired, it could be used to implement a load management system. A major portion of the project is devoted to software development; large software modules on the order of 2000 program design language statements each are required to run the integrated control system.

Distribution automation clearly involves more than a computer-based communications system. New technology must be applied at each link along the continuum from the customer's meter to the utility distribution substation. EPRI is sponsoring several support studies that should help bring electronic automation of this continuum closer to reality.

An important link is the customer's meter itself. Conventional electromagnetic watthour meters are rather limited

APPLICATIONS FOR DISTRIBUTION AUTOMATION

Applications of distribution automation encompass the full spectrum of distribution functions and facilities, from automatic feeder switching to remote meter reading. Most of these are centered at the distribution substation, but they affect operations from the control center all the way to the customer's meter. Data and command signals are transmitted between the various levels by one or more communications technologies, including power line carrier, radio, or telephone lines.

Automatic Control

Automatic bus sectionalizing
- —Fault isolation
- —Service restoration
- —Overload detection

Feeder deployment switching and automatic sectionalizing
- —Fault location
- —Fault isolation
- —Service restoration
- —Feeder reconfiguration

Integrated voltage and VAR control
- —Bus voltage control
- —Substation transformer circulating current control
- —Line drop compensation
- —Feeder remote point voltage control
- —Feeder reactive power control
- —Substation reactive power control

Substation transformer load balancing
- —Transformer load loss reduction
- —Minimization of overloads

Cold load pickup (feeder)

Manual Control

Distribution dispatch center–SCADA interface

Data Acquisition and Processing

Analog data freeze
Data monitoring
Data logging

Interface

Distribution communication interface
- —Distribution line carrier
- —Radio
- —Telephone

Protection

Automatic reclosing
Bus fault protection
Instantaneous overcurrent
Time overcurrent
Substation transformer protection
Underfrequency protection

Load Management

Load control
Remote service connection and disconnection
Pass-through commands
- —Load shedding
- —Time-of-use signal

Remote Metering

Load survey
Peak demand metering
Remote meter programming
Tampering detection

analog devices; they can neither store data nor exercise commands. Some manufacturers have developed hybrid meters by attaching electronics to conventional induction meters. Researchers expect, however, that a fully electronic, advanced utility meter will eventually be developed that is less expensive and will satisfy the various requirements of emerging load management strategies.

Analogous to the need for digital data devices at the meter point is the need for electronic voltage/current sensors on the distribution line. Conventional devices sense voltage and current magnetically, but electrical quantities must be translated to digital quantities before they can be communicated to a computer control system. To complement the major efforts in distribution automation, EPRI's future plans include development of such transducers.

A significant concern for the future in distribution automation is that the advance of digital control systems will require a much greater understanding of the electrical noise and harmonics presently found on utility distribution lines. Virtually all this noise emanates from customers' devices, which feed various sorts of electrical interference back onto the line. Equipment known to cause line noise and harmonics includes arc welders, motors, computers, and other appliances.

In a major effort to gather baseline information, EPRI has contracted with SRI International to measure and analyze electrical noise on a representative sampling of utility systems. The objective is to broadly characterize electrical interference to support the definition of requirements for distribution communications and control systems.

Using a specially equipped van, SRI will measure spectral, temporal, and amplitudinal parameters in tests on 100 feeders at 10 utilities around the country; baseline interference data will also be gathered on typical residential appliances. In addition, the project will study electrical noise generated by certain other special facilities, including EPRI's Battery

Energy Storage Test Facility, the Manhattan fuel cell demonstration project, power converters for solar photovoltaics, and arc furnaces at steel mills. Results from the project, to be completed this year, are expected in 1985. Baseline data will be forwarded to appropriate industry standard-setting organizations for further study.

Cost-benefit analysis

As the hardware for distribution automation takes shape and the outline of a fully integrated distribution system becomes clear, utilities are beginning to seriously consider the costs of designing and implementing such a system and to compare them with the value of the benefits it offers. As EPRI's William Shula, manager of the Distribution Program, points out, "Distribution automation means different things to different utilities. Some are primarily interested in the switching and control and protection functions, while others may be more attracted by the remote meter reading or load management opportunities. Because of this, each utility's economic evaluation of distribution automation will be unique."

EPRI has recently completed a project to help utilities conduct cost-benefit analyses of distribution automation. The contractors, General Electric and Public Service Electric & Gas Co., developed guidelines and methodological procedures and calculations for use in determining the benefits of automation. The guidelines enable a utility to determine its priorities among the many functions available through distribution automation and to assign specific costs and benefits to each function.

A report on the economic evaluation project is expected to be available by the end of this year. Already, however, a utility has used the approach to support a decision to implement distribution automation. In the course of its participation with General Electric in the study, Public Service Electric & Gas determined that the construction of a new distribution substation could be deferred by automating a portion of its existing distribution system. Three different automation scenarios were examined by using four financial planning models; the analysis projected that an $8 million substation could be cost-effectively deferred for 4 to 10 years.

An important consideration in a utility's assessment of distribution automation relates to the philosophy that underlies how the automated system is designed and built into the power network. As Blair explains, "There are two basic approaches to automated system design: centralized and decentralized. Depending on which philosophy is favored, the economic evaluation breaks down to a trade-off between the cost of the communications system and the cost of the balance of the system, mainly that of the computers and remote control points. Although there is really no general rule, it appears that from a cost point of view, the optimal system for high reliability and minimum expense tends toward a decentralized approach."

Planning for the future

One implication of distribution automation that is emerging from the research projects sponsored by EPRI and individual utilities is the importance of planning for an orderly and rational transition from existing distribution systems to the interactive, electronic systems envisioned for the near future.

A trend toward automated distribution systems is already clear. According to John Dougherty, it is an inevitable, logical result of the growing complexity of modern power networks. "The systems are becoming so complex and interdependent that, ultimately, you would not be able to operate the systems to their maximum efficiency and reliability without automating them," says Dougherty. "I'm sure that eventually power systems will be totally integrated and automatically controlled, monitored by well-trained engineers. But it will take a while, and it will come step by step."

New technologies such as cable television, fiber optics, and satellite systems may improve the cost-benefit ratio of distribution automation and communications systems in the years ahead. But as Dougherty points out, utilities should move ahead with distribution automation without waiting for the ultimate in communications technology.

"Distribution automation is probably cost-beneficial to most major utilities right now," adds Blair, "but implementing automation will cause significant changes in distribution engineering and operations." The immediate goal for a utility considering distribution automation should be to develop a master plan for determining the functions to be automated and the economic costs and benefits.

"Developing a master plan will take at least a year of careful and extensive study," says Blair. "The selection of a vendor could take another year. Implementing distribution automation on a large scale, even if a utility started today, would take at least 3 and possibly as many as 10 years. Thus," adds Blair, "utilities should begin their planning and economic evaluations as soon as possible. The message is clear: the potential for benefits is real, and the sooner a utility starts planning for automation, the sooner it will realize the benefits."

Further reading

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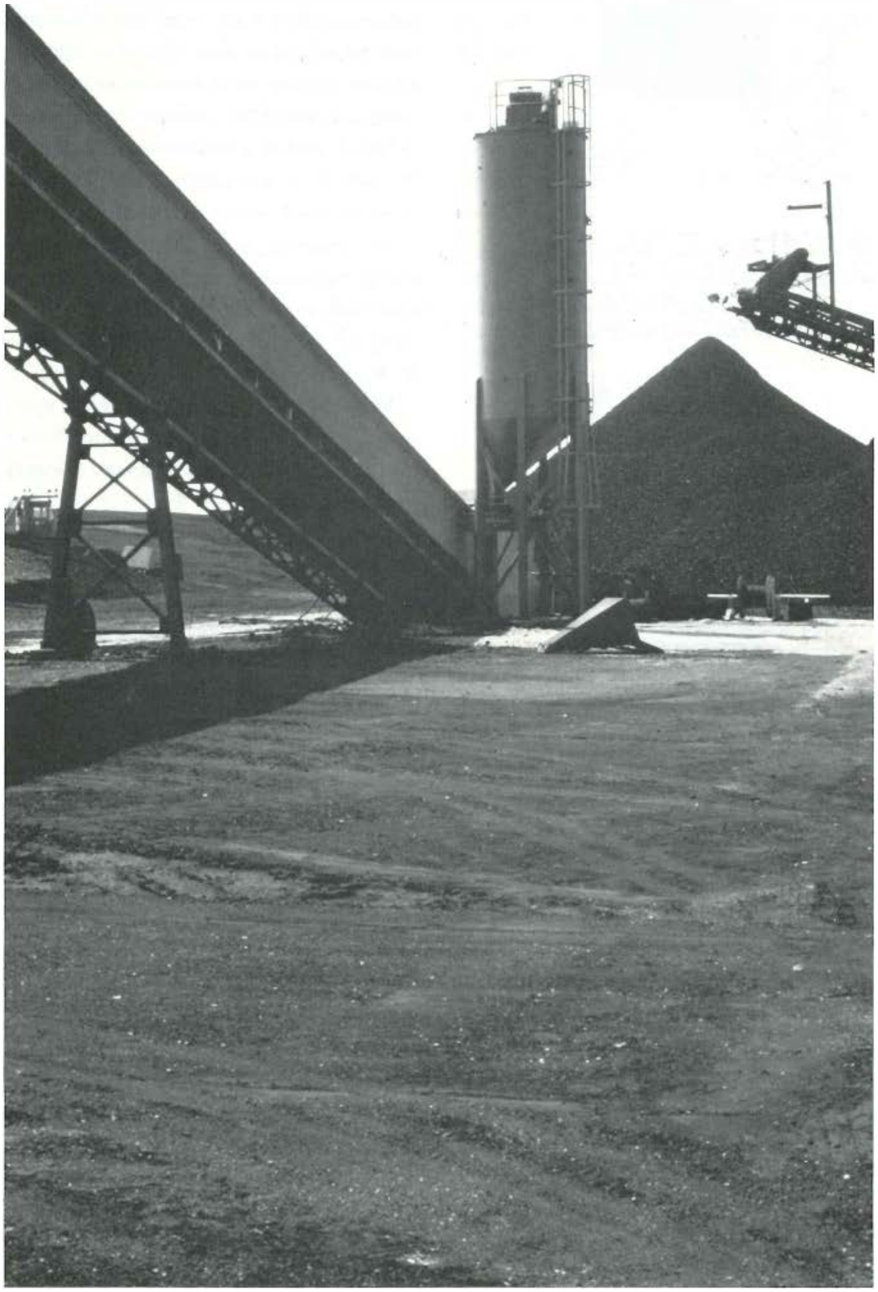
This article was written by Taylor Moore. Technical background information was provided by William Blair, Thomas Kendrew, and William Shula, Electrical Systems Division.

Utilities have successfully used sodium conditioning of coal to upgrade the performance of their hot-side precipitators.

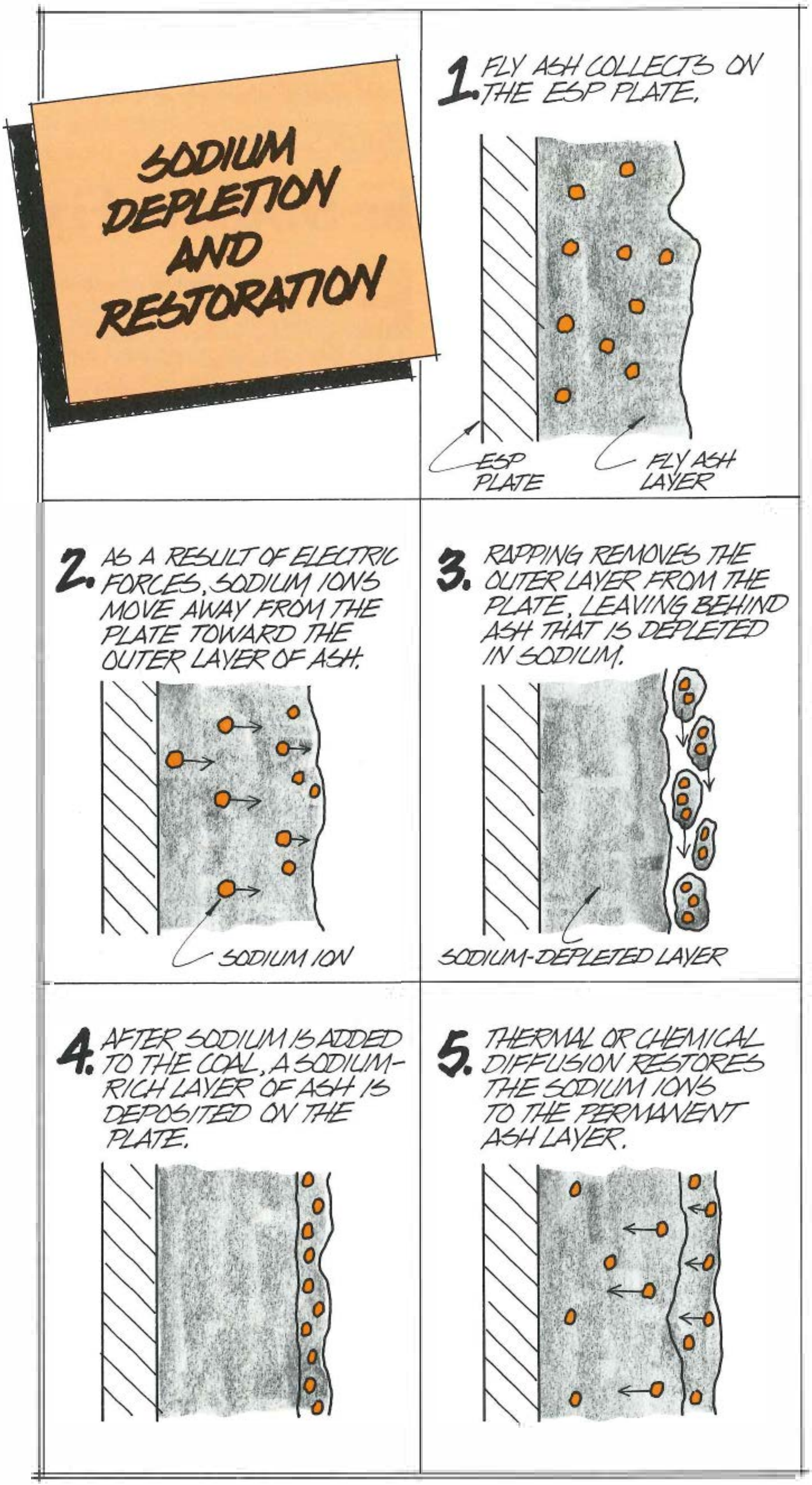
Restoring ESP Performance: The Sodium Fix



Electrostatic precipitators (ESPs) have been the dominant means of controlling particulate emissions at coal-fired power plants because of their relatively low capital and operating costs and high efficiency. These devices work by electrically charging the dust produced during coal combustion and collecting the particles on oppositely charged plates. Periodically the ash is dislodged from the plates by rappers and collected in hoppers for disposal. Particulate emission and stack plume opacity standards for new plants now require ESP efficiencies of over 99.5%.

Utilities have increased their use of low-sulfur coal in recent years to comply with stricter sulfur dioxide regulations. But fly ash from low-sulfur coals generally has a high electrical resistivity and is notoriously difficult to precipitate at temperatures commonly found on the cold (downstream) side of the air heater—about 300°F (150°C). At one time, it was generally believed that the fly ash would be easier to collect on the hot (upstream) side of the air heater, where temperatures are commonly 600–800°F (320–430°C). This belief was based on the fact that fly ash resistivity decreases at temperatures above 300°F and usually falls in the optimal range for collection at hot-side temperatures. Hot-side ESPs were thus seen as the answer to the precipitation problem with fly ash from low-sulfur coal, and they were installed in many power plants that burn such coal.

Unfortunately, in some of the plants using hot-side ESPs—particularly units in the West that burn high-calcium, low-sodium coals—precipitator efficiency began to drop off drastically after several months of operation. In many cases this



degradation in performance was eventually traced to fly ash chemistry. Field tests conducted for EPRI by the Southern Research Institute confirmed that sodium depletion in the fly ash layer that permanently adheres to the collection plates was responsible for an increase in fly ash resistivity. Specifically, under the electric field imposed in an ESP, the positively charged sodium ions in the ash layer migrate toward the source of negative corona and away from the plate. The layer next to the plate therefore becomes sodium-depleted and highly resistive to electric current. In this situation the operating current in the precipitator is greatly reduced, and as a result the collection efficiency declines rapidly. Sandblasting or washing with water will remove the sodium-depleted layer, but these procedures necessitate costly shutdowns of several days. And even after washing, the layer of sodium-depleted fly ash forms again within a few weeks or months.

In a research program jointly sponsored by EPRI, the Environmental Protection Agency, Southern Company Services, Inc., and Gulf Power Co., the Southern Research Institute began working with Gulf Power at the Lansing Smith plant in Florida to test sodium conditioning of coal as a means of dealing with sodium-depletion problems. An additive injection system was built next to the coal conveyor belt so that powdered sodium sulfate, a by-product from a nearby industrial plant, could be added to the coal before it was pulverized. Changing the concentration of sodium in the coal from the original value of 0.3% to about 1% established conditions that for this particular plant restored ESP performance and sustained acceptable performance. Adding even more sodium (bringing the level up to 1.7%) raised collection efficiency to nearly 99.8%.

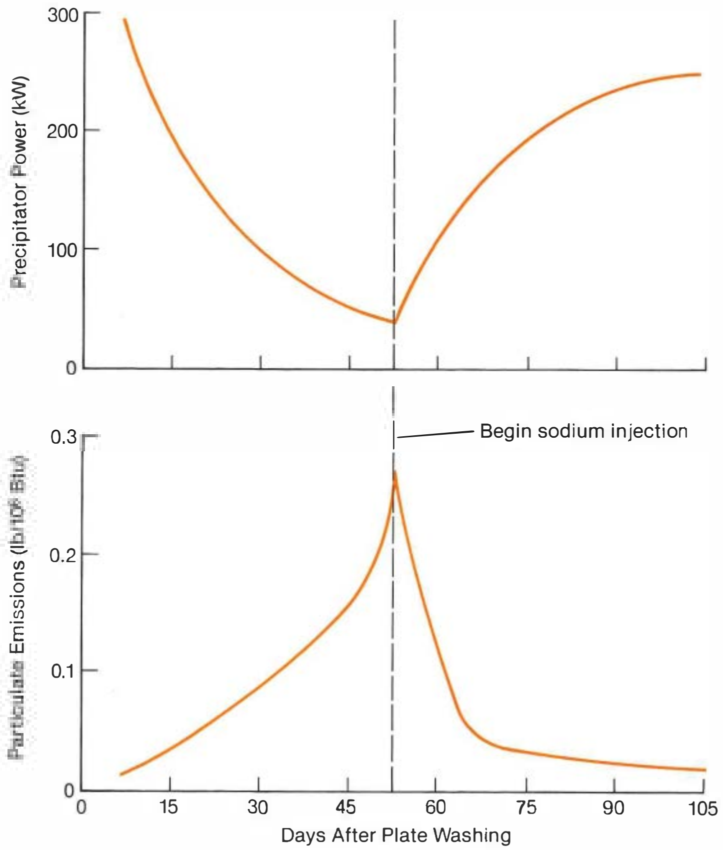
The results from the Lansing Smith plant were of special interest to Iowa Public Service Co. (IPS), whose 580-MW George Neal Unit 4 had begun commercial operation in mid-1979. The unit, designed to use low-sulfur Wyoming coal, is equipped with a hot-side precipitator. Within a few months of startup, however, the precipitator's efficiency had fallen below the design level of 99.7%, and the plant was having difficulty meeting emission standards. State agencies and the Environmental Protection Agency worked with IPS in an 18-month program to bring the plant into compliance with the regulations. The collecting plates were air-cleaned, washed with water, and sandblasted in efforts to remove the sodium-depleted layer; but, as in previous situations, those measures produced only a temporary improvement in ESP performance. By that point, IPS was considering converting the precipitator to cold-side operation at an estimated cost of $10 million. Several other coal-burning power plants that had experienced difficulties with hot-side precipitators had been forced to proceed with this expensive option.

After discussions with Gulf Power, however, IPS decided to try sodium conditioning of the coal feed. By varying the amount of sodium sulfate (or sodium carbonate, an equally effective conditioning agent) added to the coal and closely monitoring precipitator operation, ESP outlet particulate emissions were reduced dramatically—to well within regulatory limits. The installed cost of the sodium sulfate storage and delivery system was approximately $200,000, and the total annual cost for material and maintenance was approximately $400,000. Having avoided conversion to a cold-side precipitator, IPS estimates a levelized savings of over $1 million per year for the five-year period 1983–1987.

According to Ralph Altman, EPRI project manager, as many as a dozen power plants could benefit from sodium conditioning to improve hot-side ESP performance. He points out, however, that the process is site-specific and is affected by the composition of the coal burned as well as by boiler design. For example, the Lansing Smith plant uses low-sulfur, low-calcium coal. Fly ash from this coal has a high fusion temperature and does not readily foul the back-pass convective section of the boiler. Even the addition of sodium, which normally makes fly ash stickier, did not result in an appreciable increase in fouling at Lansing Smith. Fly ash from coal that is high in calcium, however, has a low fusion temperature and does tend to foul boiler back-passes. In addition, high-calcium coal requires higher levels of sodium supplementation to overcome the sodium-depletion problem; the resulting fly ash is even stickier, and the potential for fouling is increased. In some cases, steam soot blowing can be used to control this fouling problem.

Although there are limitations associated with sodium conditioning—principally the fouling problem just cited—this method of maintaining hot-side ESP performance is now being used at a number of utility plants. Sodium conditioning, first demonstrated to be effective in the tests at Lansing Smith, is currently the only method short of costly precipitator wash downs that has produced sustained acceptable performance at these plants. Future research may develop a more attractive solution to the problem, but until then sodium conditioning will make it possible for some plants to operate at full capacity at an acceptable cost. ■

Particulate emissions increase significantly as sodium depletion degrades the performance of electrostatic precipitators. In one test with newly washed plates, increasing resistivity caused ESP performance to decrease steadily for about 50 days. After sodium conditioning of the feed coal, precipitator power and emissions both returned to acceptable levels within another 50 days of operation.



This article was written by Stephen Tracy, science writer. Technical background information was provided by Ralph Altman and Robert Carr, Coal Combustion Systems Division.

DOE Pursues Endless Energy

DOE's fusion energy program has been one of the most consistently funded programs in this period of federal budget cutbacks. A look at the accomplishments and goals of the program may explain why.

Romantic is an adjective not often used to describe the federal government. But there is a certain romance in the quest to re-create the power of the sun on earth. And developing this awesome sun power technology to fuel the nation is the goal of DOE's Office of Fusion Energy.

In the past three years, while other DOE programs have faced severe budget reductions, the budget of the Office of Fusion Energy has remained relatively intact, largely as a result of congressional commitment to the program. The FY83 appropriation for fusion R&D equaled $461 million, and $471 million was appropriated for FY84. DOE requested a $12 million increase, to $483 million, for FY85; the congressional conference committee recently reduced the appropriation to $440 million, however, and this figure is the recommendation that has been sent to the president.

Although the FY85 appropriation is the lowest in three years, fusion energy remains one of DOE's best-funded, most cohesive programs. This federal interest is not new. Congress felt a strong enough commitment to the technology to pass the Magnetic Fusion Energy Engineering Act of 1980, which directs that fusion energy be available as an energy resource for the twenty-first century. The act also specifies that the federal government plan a demonstration fusion reactor for operation by the year 2000. The present funding allocation precludes achievement of that goal by that date, but DOE is pursuing a broad-based research program.

One reason for a strong federal commitment to the fusion energy program is that it fulfills the premise of the National Energy Policy Plan—"to develop promising technological innovations to the point where private enterprise can reasonably assess their risks." For the fusion program this means the demonstration of the scientific and technical feasibility of the technology. Without such help the private sector could hardly be expected to have much interest in a technology whose commercial potential will not be known until early in the next century. John Clarke, associate director for fusion energy at DOE's Office of Energy Research, stresses the strong federal commitment to fusion energy. But he explains that the goals of DOE's nuclear fusion program have changed in recent years. "When the U.S. fusion research program began in 1953, then under the Atomic Energy Commission, the goal was simply to invent a fusion reactor. But now we see it more as an effort to create a data base of information that one day could be used to build a technically feasible fusion reactor. If we compile enough information on the fusion process, we might be able to avoid the problems of other power systems when the time comes to build a reactor."

Clarke became interested in fusion technology as a graduate student in physics at the Massachusetts Institute of Technology. Before coming to DOE's Office of Fusion Energy, he ran the fusion program at Oak Ridge National Laboratory for seven years.

Clarke comments that the government's commitment to fusion was strengthened by the oil interruptions of the early 1970s, as well as by growing environmental concerns about air pollution from fossil fuels and the depletion of these fuels. At the same time, there were remarkable achievements in fusion development worldwide—in particular, in magnetic confinement research. Fusion seemed to provide the answer to all future energy supply problems. Deuterium, the main fuel source for a fusion reaction, is an isotope of hydrogen and is found in ordinary sea water; a perfect fusion process would produce more energy from one cubic kilometer of ocean water than could be generated from all the fossil fuels on the planet.

Understanding the Process

In terms of the environment and of fuel supply, fusion may approach the ideal energy source. But, as with any ideal, it also presents many major scientific and engineering challenges. Even a simplified explanation of the fusion process shows the complexity of harnessing this power. The first use of fusion to generate electricity will probably involve fusing the nuclei of deuterium atoms with the nuclei of another hydrogen isotope, tritium, which can be bred from the element lithium. The fusion process joins the deuterium and tritium atoms to create helium. As the helium is formed, an extra neutron is freed and thrown off at tremendous speeds; it crashes into other nuclei, giving up its kinetic energy and creating heat that can then be transferred and used to produce electricity. Fusing deuterium and tritium, however, requires tremendous amounts of heat—about 100 million degrees Celsius—in order to overcome the positive charges of the two nuclei, which normally cause them to repel each other.

When the two elements are heated to such intense temperatures, the electrically neutral atoms become ionized, or separated into negatively charged electrons and positively charged ions. The resulting mixture of these ionized atoms, called plasma, is very difficult to handle. For a fusion reaction to occur, the plasma must be held together or confined at an appropriate density for at least 1 second at these extreme temperatures. Once the plasma is thus confined, the nuclei will eventually fuse and create heat and energy. Yet the high temperature and density must be maintained in order for additional fusions to occur, because fusion is not a chain reaction.

The main challenge for fusion researchers has been to confine the plasma so that the nuclear fusions can occur. Plasma cannot be confined in material containers because it will hit the wall and cool itself, stopping the fusion reaction. But because every particle in the plasma has an electric charge and all charged particles react to electromagnetic forces, the plasma can be and has been confined by electromagnetic fields. Magnetic confinement is, therefore, one way to create the necessary conditions for a fusion reaction.

The other technique being explored is inertial confinement, where high-energy drivers such as lasers, electron beams, or ion beams are used to initiate the fusion process. Inertial confinement involves focusing converging beams onto a fuel pellet contained within a reactor vessel. This procedure produces the high fuel density and temperature necessary for thermonuclear energy release.

The FY85 funding appropriation provided by Congress for inertial confinement fusion (ICF) is $169 million. Currently most of this research is related to questions of weapons interest. In fact, DOE's ICF research is undertaken in the defense program area. Although the focus is now on defense applications, there are many in the fusion research community who believe that the ICF technology also has application for energy development. Richard Schriever, director of DOE's Office of Inertial Confinement, explains that "the current ICF research we are involved in would need to be done in any case. We are exploring the physics of small pellet burn, and this research applies to both defense efforts and civilian energy development."

The largest portion of ICF research is being pursued at three national laboratories; work is also under way at universities and private companies. Research into glass laser technology is being performed at Lawrence Livermore National Laboratory, the Naval Research Laboratory in Washington, D.C., KMS Fusion, and the University of Rochester. Experiments with carbon dioxide and advanced gas lasers are being conducted at Los Alamos National Laboratory. Sandia Laboratories is operating a pulse power light-ion machine for investigating fuel-pellet implosion experiments, and is building a more advanced machine—the Particle Beam Fusion Accelerator-II. DOE's ICF program is also addressing advanced driver development, since the driver is a key component of both defense and commercial ICF systems.

The Research Challenge

The inertial and magnetic confinement technologies both present scientific and engineering challenges to fusion researchers, and there are increasing challenges ahead. DOE's Office of Energy Research, which has responsibility for the magnetic confinement program, is pursuing two types of confinement concepts, based on closed and open magnetic configurations. The first, and seemingly the more prolific, is a closed magnetic system confining a doughnut-shaped plasma. There are several types of these so-called toroidal systems: the tokamak, the stellarator, the reversed-field pinch device, and, most recently, the compact toroid. The tokamak, first developed by the Soviet Union, is considered to be the most promising approach for confining a plasma. It is characterized by a strong current weaving inside the plasma to promote plasma stability. Tokamak research is the best-funded area in the magnetic fusion research program of the United States; it is also the best-funded fusion research area in Japan, Europe, and the Soviet Union.

DOE's Clarke provides some perspective on research directions: "The most difficult aspect of developing fusion energy is that there are eight separate physics issues that must be resolved to some extent in a complete plasma system before you can really begin to study any one of them in detail. It took 20 years of hard work to find a magnetic configuration with which to really advance our scientific understanding; the tokamak was the first magnetic field configuration for confining plasmas that allowed simultaneous study of all eight of these physics requirements."

Most of the U.S. tokamak research is taking place at the Princeton Plasma Physics Laboratory; other research is being conducted at GA Technologies, Inc., Oak Ridge National Laboratory, and the Massachusetts Institute of Technology. Almost all of this research is funded solely by DOE.

The Tokamak Fusion Test Reactor (TFTR) at Princeton first generated plasma on December 24, 1982, which marked the end of that project's construction phase. The TFTR is now being prepared to demonstrate scientific feasibility—that is, to demonstrate that a magnetically confined high-temperature plasma can be used to produce significant amounts of potentially useful power from fusion reactions. To achieve the high temperatures required for fusion reactions to take place, energy must be added to the plasma. The methods used to heat the plasma include electric current, magnetic compression, high-frequency radio waves, and the injection of a beam of high-energy deuterium or tritium neutral atoms. By longstanding convention, scientific feasibility will be proved when energy break-even occurs—when the amount of energy released from the fusion reaction equals the amount of energy required to heat the plasma. DOE expects to demonstrate energy break-even in the TFTR in late 1986.

Clarke

EPRI is sponsoring a research project (RP1748-1) at the TFTR that involves using a blanket module for tritium breeding. The fabrication of the test and instrumentation equipment will be completed this year, and the initial breeding experiments are scheduled for 1985. This study will be one of the first tests of the fusion fuel cycle in a reactor environment.

The next step in the production of energy from a fusion reaction will occur when ignition occurs—when enough fusion energy is produced to heat the plasma and no external heating is required. Once ignition is reached and a long-pulse equilibrium burn results, a key element of the fusion research program will have been achieved. The FY85 DOE budget provides for an increase in the system design area to fund design studies of a fusion core facility that would achieve ignition and self-sustaining, long-pulse equilibrium burn. Clarke notes, "A fusion core facility, generally known as the Tokamak Fusion Core Experiment [TFCX], would strengthen U.S. world leadership in the development of the tokamak concept. It would help us resolve basic scientific questions on the behavior of burning plasma that are essential for any future application."

The development of the device concept for the TFCX will be completed with FY84 funds, and conceptual design work will begin in FY85. DOE is hoping that researchers can achieve an ignited plasma core and also demonstrate net thermal power production in the TFCX during the 1990s.

Japan and the Soviet Union are also constructing large tokamaks—the JT-60 and the T-15, respectively. In Europe the Joint European Tokamak (JET), which is three times larger than the TFTR, has been in operation for about a year. The TFTR, however, was the first of this generation of fusion devices to produce initial test plasmas.

In addition to the toroidal research, DOE is investigating a concept that uses an open magnetic confinement system. This open-ended system is best exemplified by the tandem-mirror reactor concept, developed under DOE funding. By using a combination of electric fields and an extra-strong magnetic field at each end of a long tube-shaped vessel, the charged plasma particles are reflected back and forth long enough for a fusion reaction to occur. Tandem-mirror research is under way at Lawrence Livermore National Laboratory and at the Massachusetts Institute of Technology and several other universities.

The Mirror Fusion Test Facility (MFTF-B), under construction at Livermore, is the largest mirror system in the world. Scheduled to begin operation in

1987, the MFTF-B will be used for testing critical parameters at nearly reactor-level conditions. In fact, one of the aims of the MFTF-B is to confine the deuterium plasma under conditions close to those required for a commercial tandem-mirror reactor. Believing that more data are required to expand the existing technical base for operation of a tandem-mirror reactor, DOE has asked for $42 million for further research in FY85.

Clarke emphasizes that there are definite advantages to pursuing research on the tandem-mirror concept: "For one thing, tandem mirrors seem to require less and simpler maintenance than a toroidal reactor. For another, the tandem mirror, being a basic alternative, may sidestep some of the scientific problems of toroidal systems. However, the toroidal concept is more advanced scientifically, and that is where we will continue to place a strong research emphasis."

Alternative Concepts

The tokamak and tandem mirror are considered mainline research because they are the furthest along in terms of technical feasibility. However, there are other magnetic configurations that DOE is interested in investigating. In fact, some of these may lead to reactors that will be more appealing to utilities. The intent is to develop something smaller, cheaper, or more efficient than its mainline counterparts. Among these alternatives are the stellarator, the reversed-field pinch, and the compact toroid.

One concept that is reemerging is the stellarator, an old steady-state design of the toroidal variety, which was invented in the United States in the early 1950s. The concept was abandoned in this country in the late 1960s, when the tokamak concept proved more successful. Researchers in Germany and Japan, however, have heated plasma in the stellarator with neutral-beam injection (a method not available in the 1960s) and have achieved temperatures and confinement parameters close to those of the tokamak. Some researchers believe that a steady-state toroidal reactor will emerge from a tokamak-stellarator combination.

The reversed-field pinch device, which is being explored at Los Alamos National Laboratory, is a close relative of the tokamak in that it is toroidal and operates in pulses. Because of its extremely high power density, a reversed-field pinch reactor might be cheaper to make and more compact than either a tokamak or a tandem-mirror reactor. Private industry is apparently impressed with the advantages of this concept: GA Technologies has spent $5 million to build a reversed-field pinch device known as OHTE (Ohmically Heated Toroidal Experiment), and an additional $10 million is being spent by Phillips Petroleum Co. to operate OHTE for three full years.

DOE is also pursuing another set of alternative concepts called compact toroids, which would offer both high power density and a simple design by eliminating the coil that runs through the hole of the tokamak. These devices are undergoing preliminary testing at some of the national laboratories. Clarke explains, however, that DOE is not pursuing these alternative concepts as replacements for the mainline research: "The mainline programs have produced the scientific understanding that has made the successes in these alternative configurations possible. In turn, we have been able to use many of the ideas developed in the alternative designs and apply them to both the tokamak and tandem-mirror projects. The mainline designs are proving remarkably adaptable, while the alternatives are clearly becoming more efficient. I foresee the development of the reactor concept as a process of synthesis rather than substitution."

Fusion Technology Spin-Offs

In addition to these new compact toroidal designs, which grew out of the research on their mainline forerunners, other technological advances have resulted from DOE's research on magnetic fusion energy. As Clarke notes in the preface to a report documenting some of these successful spin-offs, "While we are all focusing our attention on the ultimate impact that an operating fusion reactor will have on mankind, we should not lose sight of the nearer-term benefits of our work."

One of the more practical applications of the research undertaken by the magnetic fusion program was the development of homopolar resistance welding. This technology was first investigated by the University of Texas, under joint EPRI–DOE sponsorship, in connection with a potential power supply for tokamaks and toroidal field magnets. The Center for Electromechanics at the university eventually developed machines for homopolar resistance welding as inexpensive tools for application in the oil and gas, nuclear power, steel, chemical, and pipeline industries. Homopolar machines have successfully welded over 20 types of alloys, including steel, aluminum, and titanium. The university is now licensing this invention to a commercial manufacturer in Texas for use in welding oil well casings.

Another technology developed out of the magnetic fusion energy program has direct application for the utility industry: superconducting magnetic energy storage. As one of the technologies needed for a fusion power plant, DOE developed large pulsed superconducting magnets capable of storing energy with little loss. Superconducting units make it possible to stabilize power transmission on long high-voltage lines and delay the need for adding costly power lines. GA Technologies and Los Alamos National Laboratory have already developed a large superconducting magnetic energy storage system for Bonneville Power Administration designed to help stabilize power transmission on a high-voltage ac line to California. This unit is installed at BPA's Tacoma substation.

In addition, the magnetic fusion energy program discovered the usefulness of transient forces in pulsed magnetic fields. Early magnetic fusion energy researchers at General Atomic Co., under utility sponsorship, found that the metal liner in a fusion experiment could collapse under transient forces. A technique has now been developed, and commercialized by Maxwell Laboratories, to form metal parts by pulsed magnetic fields. The parts are joined by shrinking rather than heat weld bonding. Many automotive parts, electric motors, electrical insulators, aircraft control rods, and even cigarette lighters are now assembled by using this technique.

International Research

"To have reached this current level of fusion knowledge, including alternative design concepts and engineering spin-offs, required an open information exchange with all countries developing this tremendous energy resource," Clarke states. "The technology is so complex that countries need to share results to make rapid progress."

The United States has had formal agreements with Great Britain since 1958, with the Soviet Union since 1959, and with Japan since 1979. Probably the first major breakthrough in fusion energy came in 1969, when the Soviets proved that the tokamak reactor concept was able to confine hot fusion plasma. Since then international agreements in fusion R&D have included advanced conceptual reactor design and engineering development.

The decades of the 1980s and 1990s should see the international development of fusion physics and fusion technology proceed at an extremely rapid rate. Major magnetic fusion experiments will continue at facilities around the world: the TFTR at Princeton, the MFTF-B at Livermore, the JT-60 in Japan, the JET in Europe, and the T-15 in the Soviet Union.

A good example of international cooperative fusion development is the Large Coil Test Facility, recently completed at Oak Ridge National Laboratory. The facility was started in 1977 under an International Energy Agency agreement to provide a facility for the testing of large superconducting magnetic coils. These coils are a critical component for providing practical and economic magnetic fields to contain fusion plasma. Japan, Switzerland, and the European Community are each building one superconducting coil to be installed in the test facility for joint research purposes. The United States will build three coils to test for common performance specifications and dimensions.

International cooperation on fusion research also exists at the Doublet fusion reactor at GA Technologies in California. Researchers there are testing magnetic confinement while trying to reduce the size of the magnets, one of the most expensive components in a fusion reactor. Japan has a team of scientists at the Doublet facility who participate in operating the device.

In addition, all the nations with major fusion development research programs send representatives to a design team sponsored by the International Atomic Energy Agency to develop a conceptual design for an engineering test device. This device was designated as the next step in fusion development after the upcoming break-even experiments. The design study for the International Tokamak Reactor (Intor) will also be used by the United States to begin its design of an engineering test reactor.

The development of fusion energy is an international undertaking, and many nations—including France, Great Britain, the Federal Republic of Germany, Japan, Italy, and the Soviet Union—are vigorously pursuing their own fusion R&D programs. The Japanese may well become the world leaders in fusion development with the JT-60 device, which is scheduled to begin operation next year.

So what does all this fusion research, domestic and international, mean for the future? The argument can easily be made that the technology is too expensive and too long-range to be practical, particularly for electric utilities that are fighting for public acceptance of fission reactors.

But, as Clarke emphasizes, "The serious nature of today's utility problems underscores the need for long-term solutions. The potential for energy from fusion is too great not to spend research dollars to develop it for the time when alternatives are needed. And, just as important, we are gaining tremendous amounts of knowledge in physics and engineering as we complete the quest for practical fusion energy." ■

This article was written by Christine Lawrence, Washington Office.

Expanding Photovoltaic R&D

To make photovoltaic technology viable for large-scale power generation, researchers will be pushing energy conversion efficiencies to their limits.

Photovoltaic (PV) power systems totaling several hundred megawatts could be installed and generating electricity in the second half of the 1990s if research continues with its present momentum. Building on that momentum, EPRI is expanding research and development in photovoltaics this year. With PV power systems getting sustained attention from private industry and government, technical advances and changes in the economic climate have also attracted the attention of utilities.

"PV technology looks like it has a good shot at success as a bulk power generating option," reports Edgar A. DeMeo, manager of EPRI's Solar Power Systems Program, "so we are increasing R&D activity in this technology." In recent months, research on concentrator systems has been expanded and a new program in thin-film PV systems has been launched.

Heightened interest was sparked by a recent EPRI evaluation of the status of photovoltaics and the outlook for its future. The evaluation results were published in *Photovoltaic Power Systems Research Evaluation* (AP-3351), a report by the EPRI Ad Hoc Photovoltaic Advisory Committee. Realizing PV's potential, according to the report, will require a sustained R&D commitment over the next 5 to 10 years.

The appeal of PV technology lies in its simplicity, explains DeMeo. "You put a system in the field and it generates electricity without rotating machinery and with few moving parts. PV has good potential for very low maintenance requirements. Also, operating manpower requirements may be very low."

The other big advantage of PV is its modularity—it is probably the most highly modular power technology on the horizon. And because PV power systems can be tested at relatively small sizes, utilities are beginning to gather experience from small-scale testing, which can be directly translated to larger systems. Field tests conducted by U.S. utilities are now approaching a total output of 10 MW.

A number of general approaches show potential for meeting—over the next 10 to 15 years—the cost and performance requirements for large-scale use by utilities. "The key is to push solar energy conversion efficiencies toward their physical limits," says DeMeo. Flat-plate PV modules will most probably require efficiencies of 15% and concentrating cells will have to achieve efficiencies of 25% or more. These targets, established by EPRI, are based on levelized busbar energy costs of 6–7¢/kWh in constant 1982 dollars.

The three approaches that currently show the most promise are tandem amorphous silicon thin films, crystalline silicon ribbons (the dendritic web is a front-runner), and high-concentration systems that use high-efficiency cells.

High-concentration PV systems have been a major focus of the EPRI program for several years, and related activity is now being increased, says DeMeo. "We are establishing a program in amorphous silicon thin films and cofunding a program addressing the key technical issues for dendritic web silicon. All of the activities are being conducted in cooperation with government, industry, and utility research efforts." ■

Indoor Air Quality Manual Now Available

Considerable effort has been devoted to cleaning up outdoor air. Meanwhile, the quality of air indoors—where most people spend the greater part of their time—has received little attention. Recent studies show that concentrations of certain pollutants inside the home sometimes exceed the national standards set for outdoors.

EPRI's new *Manual on Indoor Air Quality* (EM-3468) is a source of concise technical information for utilities and other interested parties. The manual describes the characteristics and health effects of selected pollutants and summarizes the link between pollutant concentrations, air infiltration and ventilation, and energy conservation. It also reviews current indoor air quality standards, monitoring and modeling methods, instrumentation, and pollution control measures. Technical studies, field studies, manufacturers' information, and other professional research on building performance and indoor air quality are also presented.

This manual serves as a quick guide to current knowledge about indoor air quality. Where technical information is too lengthy or complex to include, appropriate references are cited. A partial list of vendors of monitoring instruments and control equipment is also provided. For more information about the manual, contact EPRI Program Manager Arvo Lannus, (415) 855-2398; or order it directly from Research Reports Center, P.O. Box 50490, Palo Alto, California 94303, (415) 965-4081. ■

Industry Supports Liquefaction Research

Standard Oil Co. of Indiana recently announced that it will support coal research now under way at the Wilsonville, Alabama, Advanced Coal Liquefaction Research and Development Facility.

The company will contribute $300,000 annually over the next three years as part of the project's private sector funding. DOE provides two-thirds of the $11 million annual budget, and EPRI provides the balance. Southern Company Services, Inc., is the on-site manager.

The Wilsonville pilot plant is a 6-t/d test facility that has been in operation since 1974 to advance the solvent-refined coal (SRC) process and other coal liquefaction processes. Since last year, the emphasis at Wilsonville has shifted to the production of higher-quality fuel by means of the integrated two-stage liquefaction process.

In a related development, an important extension of coal liquefaction technology was disclosed by Chevron at the most recent EPRI contractors' conference on coal liquefaction. With positive results, Chevron has processed coal together with low-value (high-sulfur, high-metal) crude oil from its 100-bbl/d pilot plant. An important step for future industrial applications, coprocessing coal and crude oil can add to the country's fuel supply by upgrading low-value petroleum stocks and converting coal in a beneficial way. ■

CCTF Cleans Two Kittanning Seam Coals

EPRI's Coal Cleaning Test Facility (CCTF) continues to assess coal cleaning effectiveness. Early in 1984, the facility tested two Kittanning seam coals—one from Cambria County, Pennsylvania, and the other from Nickles County, West Virginia.

Seven hundred tons of lower Kittanning seam coal (from Pennsylvania) were provided for characterization by Pennsylvania Electric Co. (Penelec) and New York State Electric & Gas Corp. (NYSE&G). Boston Edison Co. contributed 1000 tons of upper Kittanning seam coal (from West Virginia). Boston Edison is evaluating this coal for possible use at the New Boston and Mystic stations after they are converted from oil to coal in 1987.

Penelec and NYSE&G wanted to know whether the Cambria County coal could be cleaned to reduce its SO_2 emission potential to 1.2 lb/million Btu and, if so, what the yield and Btu recovery would be. The utilities also wanted to determine the extent to which cleaning would increase volatile content.

Test results showed a reduction in ash content from 24.84% in the raw coal to a range of 5.81–9.98% in the cleaned coal at Btu recoveries between 83 and 94%. At the same time, sulfur was reduced from 1.40% to between 0.77 and 0.96%, and heating value increased from 11,510 Btu/lb to a range of 14,069–14,820 Btu/lb.

Although the West Virginia coal provided by Boston Edison is of the same geologic age and origin as the Pennsylvania coal, the two types exhibited few similarities. The West Virginia coal had much higher volatiles, lower grindability, higher sulfur content, and slightly lower heating values, leading to higher SO_2 emissions. However, since Boston Edison plans to install flue gas desulfurization equipment in units where the coal will be burned, the sulfur values produced at the CCTF still meet its specifications.

By testing the coal from Penelec, NYSE&G, and Boston Edison, the CCTF is gathering data on the sulfur-reduction potential of various coals and assessing the changes in combustion characteristics that result from coal cleaning. Having access to a variety of coals allows the CCTF to test new equipment and new methods of cleaning, dewatering, sampling, and handling coal.

Coal quality data and improvements in state-of-the-art coal cleaning technology will benefit utilities in coal purchasing decisions, power plant performance assessments, and compliance strategy planning. ■

CALENDAR

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

SEPTEMBER

20–21
BENCHMARK: A Chronological Generation Simulator
Boston, Massachusetts
Contact: Jerome Delson (415) 855-2619

26–28
Symposium: Demand-Side Management
New Orleans, Louisiana
Contact: Ahmad Faruqui (415) 855-2630

26–28
Workshop: Analysis of Plant Performance and Safety—Modular Modeling System Code Release
New Orleans, Louisiana
Contact: Murthy Divakaruni (415) 855-2409 (nuclear plants) or Frank Wong (415) 855-8969 (fossil fuel plants)

16–18
Seminar: Buildings and Their Energy Systems—Technologies and Planning Strategies
St. Louis, Missouri
Contact: Orin Zimmerman (415) 855-2551

16–18
Hydro O&M Workshop and Seminar: Dam Safety
San Francisco, California
Contact: James Birk (415) 855-2562

23–24
Seminar: Estimating Retrofit FGD Costs
Denver, Colorado
Contact: Thomas Morasky (415) 855-2468

23–25
Workshop: Power Plant Performance Monitoring
Washington, D.C.
Contact: Frank Wong (415) 855-8969

31
Integrated Lake Watershed Acidification Study
Washington, D.C.
Contact: Robert Goldstein (415) 855-2593

OCTOBER

8–10
BWR Corrosion, Chemistry, and Radiation Control
Palo Alto, California
Contact: Christopher Wood (415) 855-2379

9–11
Seminar: FGD Chemistry and Analytical Methods
Atlanta, Georgia
Contact: Dorothy Stewart (415) 855-2609

10–12
Incipient Failure Detection in Power Plants
Orlando, Florida
Contact: John Scheibel (415) 855-2850

15
Seminar: Coal Transportation Costing
Kansas City, Missouri
Contact: Edward Altouney (415) 855-2626

15–18
Seminars: Fuel Supply
Kansas City, Missouri
Contact: Howard Mueller (415) 855-2745

13–16
Symposium: Dry SO_2 and Simultaneous SO_2–NO_x Control Technologies
San Diego, California
Contact: Michael McElroy (415) 855-2471

14–16
Symposium: Market Research for Electric Utilities
Dallas, Texas
Contact: Joseph Wharton (415) 855-2924

28–29
6th Annual EPRI NDE Information Meeting
Palo Alto, California
Contact: Soung-Nan Liu (415) 855-2480

NOVEMBER

5–7
Electric Field Effects Research
St. Louis, Missouri
Contact: Gordon Newell (415) 855-2573

8–9
15th Semiannual ARMP Users Group Meeting
Hartford, Connecticut
Contact: Walter Eich (415) 855-2090

13–14
Regional Conference: Compressed-Air Energy Storage
Washington, D.C.
Contact: Robert Schainker (415) 855-2549

13–15
Preventive Maintenance Model
Charlotte, North Carolina
Contact: Howard Parris (415) 855-2776

13–15
Seminar: Condenser Failures
Palo Alto, California
Contact: Barry Syrett (415) 855-2956 or Roland Coit (415) 855-2220

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

SOLID BY-PRODUCTS MANAGEMENT

EPRI's subprogram on solid by-products management covers the utilization of solid by-products (discussed in the June 1984 Journa:*) and many facets of utility disposal issues. This report discusses technology development for the selection, monitoring, and operation of ash and flue gas desulfurization (FGD) sludge disposal sites; the detection, cleanup, and disposal of polychlorinated biphenyls (PCBs); and the identification, treatment, and disposal of low-volume wastes.*

Sludge and ash disposal

Over the last two years the subprogram has focused on the disposal of FGD sludge and coal ash. Work in this area has resulted in a series of manuals on by-product disposal that cover methods and costs of site design, construction, and operation. The manuals are updated as needed to reflect evolving technology and utility practice. The current editions are *Flue Gas Desulfurization By-Product Disposal Manual,* 3d ed., CS-2801, January 1983; *Coal Ash Disposal Manual,* 2d ed., CS-2049, October 1981; and *Manual for Updating Existing Disposal Facilities,* CS-2557, August 1982.

In addition to the disposal manuals, the subprogram has developed two computer code manuals and software for estimating the costs of ash and sludge disposal systems. Each manual discusses code development, describes the program, and presents program results. These manuals, *ASHDAL: Model for Estimating Ash Disposal Costs* (CS-2368-CCM) and *SLUDGECOST: A Cost Prediction Model of FGD Sludge Disposal Systems* (CS-2556-CCM), are available from the Electric Power Software Center.

Many coal-fired plants are located in congested areas where the availability of land for coal combustion by-product disposal is limited. Land requirements for disposal sites can be reduced by compacting the waste material and by reclaiming the area after the disposal site is filled.

A project to evaluate several reclamation methods for disposal sites was completed in 1983 (RP1685-6). The purpose of this study was to investigate and summarize existing methods of stabilizing soft and loose soils and man-made fills, and to consider the applicability of these techniques to disposal site reclamation. The study evaluated 14 techniques and concluded that three methods for stabilizing the large areas common to disposal sites are promising: dynamic consolidation, surcharging, and groundwater lowering. The project included a survey of over 200 utilities, which resulted in the identification of 21 potential demonstration sites for testing the recommended techniques (CS-3475).

A major goal of the solid-waste disposal regulations under the Resource Conservation and Recovery Act (RCRA) is to maintain groundwater quality around disposal areas. Several important EPRI projects in this area relate to groundwater protection: the publication of a manual on monitoring methods, laboratory testing of candidate liner materials, field evaluations of groundwater protection methods, and the publication of simplified engineering groundwater models for site selection and monitoring support.

Groundwater monitoring and model development were the objectives of a five-year project that has just been completed (RP1406). The monitoring study was conducted at the Columbus and Southern Ohio Electric Co.'s Conesville station. It assessed the performance of the utility's disposal operation, which is based on FGD sludge fixation by adding lime and fly ash. The final report on the entire monitoring program was published in September 1984 (CS-3702). The results indicate that no leachate has permeated the landfill at Conesville. The permeabilities of the fixated sludge collected at the site were found to be higher than in the laboratory-scale tests, but comparative testing showed the fixation process to reduce significantly the concentrations of some chemical species in leachates of the fixated FGD sludge. (The comparisons were with untreated FGD sludges.)

Battelle, Pacific Northwest Laboratories has developed models and computer codes for both saturated (VTT) and unsaturated (UNSAT1D) groundwater flow (RP1406-1). The unsaturated flow code, UNSAT1D, uses a fully implicit finite-difference technique to simulate one-dimensional flow through a partially saturated flow system. The code is capable of simulating infiltration, vertical seepage, and uptake by plant roots. These phenomena are functions of a soil's hydraulic properties, soil layering, root growth characteristics, evapotranspiration rates, and the frequency, rate, and amount of precipitation and/or irrigation. A report documenting code application to the coal ash and dry FGD waste disposal site at the Antelope Valley station near Beulah, North Dakota, was published in July 1983 (CS-3173). The UNSAT1D code is now available in an IBM 370 version as well as the PDP 11/70 version. Both are available through the Electric Power Software Center under licensing agreements.

Another result of this project was the comparison of two groundwater flow codes for application to disposal site clay cap performance assessment. Leachate production after disposal site closure has become an issue in the disposal site permit process. EPA developed the HELP code in 1983 to simulate fluid flow in a closed landfill. The UNSAT1D code has the flexibility to simulate the performance in capped disposal areas, so the performance of both codes, using two kinds of cover designs simulated under three climate conditions, was evaluated (CS-3695). The results indicate that under humid conditions the two codes predict similar flows through the clay caps. In semihumid and arid environments, the HELP code predicts significantly greater soil moisture storage in the cover, whereas the UNSAT1D model predicts that the water will migrate upward from the cap and waste and then be lost to evaporation. This occurs because for those soils the capillary pressure terms can dominate the leachate transport equations; thus a more sophisticated modeling approach incorporating capillary effects is required.

In certain groundwater flow regimes, contaminant migration can be controlled by groundwater withdrawal and/or injection schemes. Determining optimal well location and pumping rates is a time-consuming iterative process. Under RP1406-1 Battelle developed a method that couples nonlinear mathematical programming with a groundwater flow and contaminant transport model. This method is a useful tool for analyzing a wide range of contaminant control objectives. An article on this approach will soon be published in the journal *Water Resources Research.* EPRI's Environmental Assessment Department will do additional work as part of its generic model development efforts (RP2485).

PCB research

PCBs continue to be a topic of environmental regulatory concern for the electric utility industry. During the past year the emphasis of the Heat, Waste, and Water Management Program has shifted from PCB equipment destruction to combustion by-products and spill cleanup.

Two projects to develop alternatives to PCB capacitor incineration involved PCB arc pyrolysis (RP1263-12) and PCB capacitor chemical detoxification (RP1263-7). The Distribution Program in the Electrical Systems Division will continue work on RP1263-12. The proposed system will accept whole capacitors as feed material, melt down capacitor shells in the arc furnace, and break PCBs down to simpler chemical units (i.e., carbon and hydrochloric acid). The resulting gases, much lower in volume than those encountered when PCBs are oxidized in air, will be scrubbed clean before being discharged to the atmosphere. This system is movable, so the furnace can be taken to a location where utility capacitors have been collected, and then moved on to another site when the PCB inventory has been destroyed.

In the area of PCB spill cleanup, the emphasis has been on instrumentation to help utilities measure PCB contamination in soil at spill sites. The most promising of the three projects funded by this program is the development of a field-portable electron capture gas chromatograph dedicated to PCB analysis (RP1263-9). The system has a built-in microprocessor to analyze the chromatographic signals, match the substance against four common Aroclors, show the concentration in parts per million, and show an error range estimated from the quality of the match. Two other projects have attempted to develop spectroscopic methods of analysis, infrared (RP1263-10) and ultraviolet (RP1263-13).

Another part of the spill cleanup program focuses on problems associated with large-area contamination. For example, if a hired waste hauler has improperly disposed of PCBs and does not have sufficient resources to accomplish the remedial cleanup, the utility faces the potential of shared liability until the PCBs are destroyed. Two projects are addressing that type of problem: soil washing (RP1263-15) and biotechnologies (RP1263-16). The objective of soil washing is to clean the dirt and replace it, while destroying the PCBs. Laboratory tests show this technique to be promising, and a pilot test of a 55-gal (208-L) system is being planned. In response to frequent utility inquiries about biotechnologies, a draft review document has been prepared; a published version should be available shortly.

Utilities have become increasingly interested in PCB combustion by-products. Fires in office buildings in Binghamton, New York, and San Francisco, California, in which PCB transformer fluid was partially combusted, have caused costly and widely publicized cleanup efforts. As a result, EPA is scheduled to establish PCB transformer regulations within the next year. To provide information about PCB combustion by-products and their relationship to electrical equipment fluids, a document was prepared that addresses PCB incidents, basic chemistry, toxicology, and analytic methods and includes an extensive bibliography (CS-3308).

Other PCB projects EPRI is considering include the documentation of the Binghamton and San Francisco fires and the development of some engineering modifications to transformer vaults that can reduce contamination risks. In addition, EPRI's program on spills will field-test the portable gas chromatograph, document a case where isolation was found to be an acceptable alternative to excavation, and investigate PCB transport behavior in soil.

Low-volume waste

The high-volume solid by-product materials generated by fossil fuel combustion have been well characterized in terms of whether they are classified as hazardous or nonhazardous under RCRA. Less well characterized than the so-called high-volume by-products (fly ash, bottom ash, FGD sludge, and slag) are the low-volume materials, such as water-side boiler cleaning wastes, fire-side washes, air preheater washes, demineralizer wastes, coal pile runoff, cooling-tower sludges, and coal-cleaning wastes. Common disposal practices are to combine the low-volume streams with the high-volume materials and codispose of them in a landfill. A current project attempts to evaluate the hazard classification associated with low-volume waste (RP2215-1). A number of utility waste stream samples have been collected and tested by the federal RCRA extraction procedure, as well as by California and Texas extraction tests. The only waste stream that may potentially be classified as hazardous on the basis of the federal procedure is boiler water-side wash, although representative sampling of that stream is an issue yet to be resolved. In Texas all the wastes would be classified as Class II wastes; in California all the wastes would be classified as hazardous. A final report on the project is being prepared, and work is about to begin on laboratory modeling of codisposal.

Waste containment

Disposal requirements for hazardous and nonhazardous materials are formulated to protect groundwater. Landfill sites must have low permeability, either from natural geologic formations or because of the installation of natural or synthetic liner materials. One EPRI project addresses liner selection and has tested a number of synthetic and natural materials (RP1457-1). A forthcoming document will describe these experiments, and it will be followed by a report summarizing data on liners that have been reexamined after approximately one year of exposure.

Preliminary results show that synthetic liners exposed to fly ash have changed very little from the test measurements made before exposure. The soil-type liner materials were found to have very low permeability, and the amount of liquid collected tended to be about 2% of a pore volume (the amount of fluid present in the pores of the clay), with the highest measured quantity under 50%. These quantities are small enough that no useful conclusions can be reached except that the liner materials seem to be withstanding any chemical reaction with waste materials. *Project Managers: Dean Golden and Ralph Komai*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

ROTATING ELECTRICAL MACHINERY

Emergency operation of motors with cutout coils

Winding failures in the stators of auxiliary power plant motors occur fairly frequently. Particularly critical are induced- and forced-draft fan motors and boiler feed pumps in conventional coal-fired plants. Motor failures rarely occur at convenient times but instead often necessitate emergency procedures, which in themselves can be costly. When essential machines are affected, significant load reductions are required—or even the shutdown of a main turbine generator—until the critical motors can be repaired.

It is usually possible to jump or cut out the failed coil and to operate the motor safely, sometimes at full load; but frequently the motor can be operated only at some reduced load level until permanent repair or replacement can be arranged. In many cases, particularly with large motors, simply jumping a failed coil will not permit successful operation because of overheating, magnetic pull, or excessive vibration.

The selection of a satisfactory reconnection method is complicated by the extreme variation in winding and connection schemes employed by manufacturers to meet design requirements. Whether a successful temporary reconnection can be made by the utility maintenance and engineering staff without outside help depends on the level of information on file for each motor and on the degree of competence and technical sophistication of the staff. Unfortunately, however, it is frequently necessary to contact the motor manufacturer to obtain the information required to safely reconnect the motor, which may take several days. In the meantime, the generator may be shut down or operating at reduced load, with consequent economic losses to the utility.

A project has been funded to develop a manual that will permit power plant maintenance personnel to quickly and effectively jump or otherwise reconnect an auxiliary motor that has a winding failure (RP2330). The manual should help operators determine the maximum load at which the motor can be operated safely until such time as a scheduled unit outage enables permanent repair or replacement. It should be emphasized that repairs made in this manner are temporary, allowing operation of the motor for only a few weeks or months. *Project Manager: J C. White*

POWER SYSTEM PLANNING AND OPERATIONS

Advanced disturbance analysis techniques

The trend in electric power system planning and operation is toward more complex networks, long-distance power transmission, and sophisticated control strategies. This results in systems that are pushed closer to their physical limits. Advanced analysis techniques are required that will enable engineers to calculate these limits, ascertain how systems fail, and design measures to prevent failures.

Purdue University researchers are testing an approximation (using symmetrical components) to simulate unbalanced (non-three-phase) faults in transient stability programs (RP1999-2). A balanced three-phase model was compared with the approximate model (symmetrical components); the results show that the symmetrical component approximation is acceptable if the correct data are chosen. Specifically, if generator subtransient reactances are being modeled, the fault impedance should be calculated by using zero sequence quantities only. If transient reactances are being modeled, the fault impedance should be calculated by using both negative and zero sequence impedance. The project's final report will be available early next year. *Project Manager: James V. Mitsche*

Optimization of reactive volt-ampere (VAR) sources in system planning

The VAR optimization problem in system planning is concerned with the location, amount, and type of new reactive power devices required on bulk power systems. The object is to ensure an acceptable voltage level under various system conditions. Although numerous optimization approaches have been proposed in the past for VAR allocation, all have major shortcomings; most do not exploit the VAR and voltage control capabilities of various devices, and few have the capability of analyzing practical, large-scale (≥1500-bus) electric utility systems.

A two-year project initiated in November 1981 with Scientific Systems, Inc., addressed these shortcomings (RP2109). Methods developed in this project are suitable for determining the optimal amount and location of new reactive power sources, while taking into account the voltage control requirements and constraints of system operating needs. The methods were incorporated into a large-scale prototype computer program, and the program was tested and verified by using actual utility system data.

VAR allocation and dispatch problems in system planning and operation are interrelated, and a two-level optimization procedure had to be used in this project. The level 1 optimization solved the short-term operational problem, achieved the optimal dispatch of available reactive power sources, and maintained voltage level under various system conditions. A code for VAR dispatch optimization was employed for this level. The level 2 optimization solved the long-term planning problem and determined the number of locations and the amount of new reactive power sources in each to minimize the overall cost of reactive power installation. A code to determine the discrete size of VAR sources was employed for this level.

The project has been completed, and the final report should be available by the end of the year. The prototype computer program should be available for distribution through the Electric Power Software Center by early 1985. *Project Manager: Neal J. Balu*

DISTRIBUTION

Prediction of URD cable corrosion

The corrosion of copper concentric neutral wires of underground residential distribution (URD) cables has been reported in almost every region of the United States. A continuous metallic electrical path through copper concentric neutrals is important to ensure the proper operation of protective devices and the safety of equipment and personnel, to balance voltages, and to minimize the possibility of stray voltages.

No highly reliable way to detect in situ corrosion of copper concentric wires has been discovered. Nor do utilities have a method of predicting whether corrosion will occur before new cable installation. Thus EPRI initiated a project to develop a reliable and practical method, based on available data, by which a utility engineer can assess the probability that copper concentric neutral wires are corroding or that conditions are favorable for corrosion to occur where new cable installations are planned (RP2200).

Harco Corp., the project contractor, has gathered the corrosion data available in the industry by examining past studies. These data are being analyzed to determine which factors have an influence on the corrosion of copper concentric neutral wires and to develop a mathematical model that will predict the probability of corrosion.

On the basis of the analysis to date, it appears that soil surface potential and soil resistivity have an influence on the likelihood of corrosion. A preliminary mathematical model has been developed that indicates the probability of corrosion for a given potential and resistivity value. Additional work is being carried out to confirm the validity of the model. *Project Manager: Harry Ng*

TRANSMISSION SUBSTATIONS

HVDC converter stations rated above 600 kV

R&D is being pursued worldwide to establish design parameters for dc overhead lines and, to some extent, for dc cables for pole-to-ground voltages in the range of 600–1500 kV. To plan such systems it is essential to know that the converters needed for the interface between the ac and dc circuits can be built. Thus EPRI and CEPEL (the R&D arm of the utilities in Brazil) have jointly funded a study to assess the potential problems of building high-voltage converters and to define the R&D needed for their design. The study has concentrated on 800-, 1000-, and 1200-kV pole-to-ground voltages, with emphasis on the lower end.

The project was divided into two parts. Engineering studies (RP2115-4) to determine converter station characteristics and dc transmission economic aspects were assigned to Themag Engenharia Ltda, a Brazilian consulting firm, which was assisted by the technical staff of Eletrobras, a holding company, and Furnas, one of its regional utilities. The identification of R&D requirements for converter station equipment (RP2115-5) was assigned to the Institut de Recherche d'Hydro Québec of Canada. The effort was optimized by the joint preparation of questionnaires for manufacturers and utilities and by joint meetings with them.

The engineering studies considered dc currents in the range of 2.5–3.5 kA and dc voltages in the range of 600–1200 kV; these correspond to power transmitted in the range of 3000–8400 MW per bipole. Transmission distances were assumed to vary from 500 to 2500 km (310–1550 mi). Initial main converter configurations were defined by considering from two to four 12-pulse converter units per pole and 600 kV as the maximum 12-pulse unit voltage. The lower end of this power range may be most relevant to U.S. conditions, whereas the upper end may be of most interest to Brazil and other countries with a similar distribution of resources and loads.

The study included the preparation of mini-specifications for dc systems, which were sent to utilities and manufacturers for review and comment. After agreement was reached on the essential parts of these specifications, follow-up discussions were held with the participants to define the problem areas.

The participants included a number of U.S. and Brazilian utilities, as well as most of the dc system suppliers in the world. Some of the major conclusions of the study follow.

- Very high converter transformer ratings (associated mainly with the higher voltages) present potential difficulties in the areas of weight, dimensions of the largest item, and transformer cooling.

- The energy stresses for the converter bridges of highest potential require arresters with a large number of parallel columns. The energy handled by the arresters is more manageable with a smaller number of converter units per pole.

- The dc filters should be as small as possible to reduce stresses on arresters.

- The dc line prefault conditions have significant influence on arrester stresses.

- The insulation margins should be as low as possible because of the very high insulation levels required. A 1200-kV system requires basic switching levels from 2550 to 2700 kV and basic insulation levels of about 3350 kV.

- The major technical problems appear to be associated with the oil-paper insulation structures of transformers and reactors. Bushings may also pose problems because of the dimensions and the electrical stresses on external surfaces of the bushings.

The study is nearing completion, and publication of the final report is scheduled for later this year. *Project Manager: Stig Nilsson*

Active and reactive power modulation of HVDC systems

Power modulation of HVDC converters has been used successfully to increase the power transfer capability of an ac-dc power transmission system. The utilities involved gained significant benefits through a fairly modest investment in control equipment. However, the modulation of the active power normally changes the reactive power flows at a converter, which changes the voltages in the ac system. The purpose of work under RP1426 is to investigate control techniques that will mitigate this coupling by both active and reactive power modulation, thereby improving the efficiency of the modulation controls.

The contractor, General Electric Co., conducted digital simulator tests for development and validation of the modulation algorithm. The power modulation is accomplished by modulating the current of the rectifier and, at the same time, the voltage of the inverter. Choosing the right proportion of current and voltage modulation signal strength can minimize ac voltage changes. The algorithms developed were installed in a digital hardware system and tested on General Electric's HVDC simulator. Through these tests the concept has now been fully proved.

Two algorithms were developed and tested. One uses the ac power flowing in a tie line parallel to the dc line as an input signal to the algorithm. The other uses the converter bus frequency as the input. During the first dc simulator test of the developed controller, it was discovered that the bus frequency–based control algorithm was unstable. It was found that the design was accidentally based on the relative inverter bus frequency instead of the absolute frequency at the rectifier ac bus. This mistake, which arose very early in the project, is also reflected in the phase 1 report, EL-2101, published in November 1981. The algorithm was modified for absolute rectifier bus frequency input and retested on the dc simulator. The results were as predicted, and the performance matched the results from using the ac power as the input signal.

The robustness of the controller was also checked by adding machines and by changing machine parameters. Such changes were made in the simulated rectifier ac network as well as in the inverter network. These checks indicated that the controller is robust—in other words, it does not cause any system instabilities or severe reduction in the system damping even for large changes in the ac networks.

The developed modulation controller has passed extensive simulator tests. Hence, any utility that has marginal stability of an ac-dc transmission system should be able to use the method with confidence. Of course, the algorithm needs tailoring and verification for each individual application, but the method appears to be sound.

Considering the cost differences between oil, coal, and hydro power generation, there could be substantial economic benefits from the use of control concepts of this type to improve the stability margins of the ac network and thereby allow for higher loading of key ac tie lines. This could be an inexpensive supplement (if one owns a dc link) to other stability enhancement techniques. *Project Manager: Stig Nilsson*

Fault location device for HVDC transmission lines

Existing systems for locating faults on HVDC transmission lines depend on the reliable communication of signals and are costly. It is important to have fault locators on dc lines because the lines are usually quite long and expensive to patrol and because the loss of revenue during an outage can be high. Therefore, EPRI initiated a project to develop a low-cost fault locator for HVDC lines (RP2150). The fault locator will primarily use information available from just one end of the line. The approach is to find fault-caused stationary voltage minima by conducting an analysis of the traveling waves produced by the faults.

The newly developed fault locator uses a simple passive reflectometer approach, which involves measuring the times between the multiple reflections of traveling waves produced by a fault. Although the concept of observing multiple reflections is not new, several new algorithms are being developed to implement time measurements, and these algorithms are key to the success of the passive reflectometer scheme.

The hardware consists of a multichannel data acquisition and processing system (off-the-shelf electronic components). Voltage and current data are filtered and sampled at a rate of about 25,000 samples a second. This rate is not very critical, although accuracy is lost at significantly lower rates. Disturbances are detected by a digital filter that processes the sampled voltage data when the detector responds to sudden changes, as indicated by the difference between a voltage measurement and the smoothed voltage provided by the filter. The sampled data, saved in response to a detected fault, are processed to yield the fault location. The location accuracy afforded by this technique would be about 4 mi (6.4 km); however, an improved accuracy of about 1 mi (1.6 km) is achieved by a simple four-sample triangulation interpolation algorithm.

Such a system has been developed and installed on the Bonneville Power Administration's northern terminal of the HVDC Pacific Intertie. Any data recorded will be used to verify the performance of the dc line fault-locating algorithms developed for this system. The fault locator is capable of predicting a fault site to within about 1 mi on the 800-mi-long (1300-km) intertie line. *Project Manager: Harshad Mehta*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

INDOOR AIR QUALITY

Over the last decade the air quality of indoor environments, especially of residences, has received increasing attention. This topic is quite important from the public health standpoint. For one thing, the careful consideration of indoor air quality can ensure that the hazards of outdoor ambient air pollution are properly evaluated. Also important in terms of public health are the suspected or potential hazards of pollutants that are generated indoors by unvented heating and cooking appliances, building materials, furnishings, and various human activities. EPRI is interested in indoor air pollution in both these connections. A more accurate determination of the health effects of outdoor air pollution in urban areas is an obvious utility industry concern with respect to fossil fuel power plant emissions. And pollution from indoor sources is of concern because conservation and weatherization programs promoted by electric utilities may be a factor in the buildup of harmful substances inside buildings. This report reviews some of EPRI's activities on indoor air quality.

One of the main techniques for evaluating the human health risks from air pollution is the epidemiologic approach; that is, researchers observe the occurrence of selected diseases or other indexes of health status in community populations and try to relate their findings to the quality of the air people are exposed to in the course of normal living. In the past most epidemiologic studies focused on the outdoor environment and relied heavily on outdoor air quality measurements to establish exposures, effectively ignoring air quality indoors, where people spend a majority of their time. This could have biased estimates of the effects of outdoor air pollution on health, since contaminated air inside buildings, mostly attributable to indoor sources, might have had an important effect on the particular disease or other health outcome under study.

Combustion-associated pollutants from heating and cooking appliances (some of the same gases and particles that are of principal concern in outdoor air) are important in this regard. Probably just as important are other contaminants unrelated to outdoor pollutants, such as substances in tobacco smoke and certain allergenic materials. Another factor to be considered in connection with indoor exposure is the passage of air in and out of structures. Air infiltration may let in pollutants from the outside; however, without adequate ventilation, substances may become trapped inside and build up to high concentrations over time.

Today researchers realize that they must account for indoor air quality in epidemiologic studies of air pollution, especially in view of the widespread improvements in outdoor air quality. Measuring air quality inside as well as outside residences to better assess exposures has been an integral part of the Harvard Six-Cities Study. This study of the long-term respiratory health effects of air pollution in community population samples of both children and adults is being jointly sponsored by EPRI (RP1001-1), the National Institute of Environmental Health Sciences, and the Environmental Protection Agency. The six cities were selected on the basis of historical data available in 1974 to represent a range of outdoor air pollution levels.

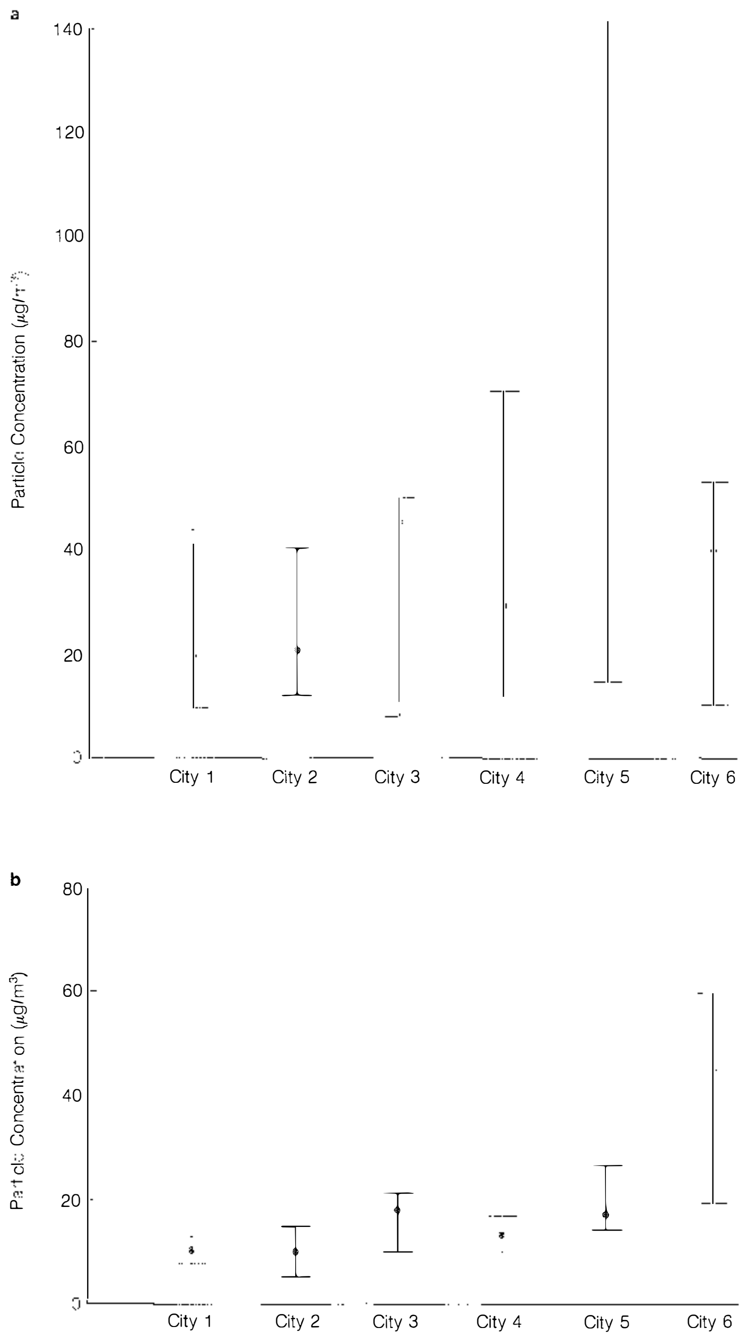
Research to date has documented how inside and outside pollutant levels vary between and within the six cities. For example, Figure 1 presents overall mean concentrations of respirable (fine) particles for each city, along with ranges of monitoring-site mean values. Clearly, in all cases except city 6, the overall indoor mean levels are higher than outdoor levels. Also, again except for city 6, there is little variation in outdoor levels across sites within a city. In contrast, the range of indoor levels for each city is considerable; these ranges overlap across the cities, which means that some residents in all six have the same indoor exposure. These data reflect the importance of indoor sources in determining indoor concentrations, as well as the importance of dwelling characteristics that affect the indoor-outdoor exchange of air. For example, the site in city 5 with an extremely high indoor annual mean concentration of respirable particles (144 $\mu g/m^3$) was a tightly sealed, central-air-conditioned home where both occupants were cigarette smokers.

These and other preliminary findings have pointed out the necessity for obtaining data on individual study participants to examine how total personal exposure relates to estimates based on average indoor and outdoor pollutant levels. The Harvard investigators are now developing an air monitoring system for characterizing the home environments of at least 300 study subjects in each of the six cities. This program will focus on nitrogen dioxide (NO_2), carbon monoxide (CO), and respirable particles; on the indoor sources of these pollutants; and on air exchange (ventilation) rates. More detailed personal and indoor peak-level monitoring will follow. The objective is to derive individualized exposure estimates for the more than 20,000 subjects in the study. These estimates, along with data from 14 years of periodic standardized health examinations, will eventually be used in analyzing indoor and outdoor air pollution effects.

Indoor air quality monitoring and exposure assessment have also been performed as part of a recent epidemiologic study by the University of Arizona. This study is examining the roles indoor and outdoor air pollution may play in explaining the daily health responses measured in 117 asthmatic and nonasthmatic families in a single community. Researchers collected air samples between 1979 and 1981 to monitor combustion gases, suspended particulate matter, and airborne allergens (pollen, algae, and fungi). Under RP2378-5 EPRI is supporting the continued analysis of these data for possible relationships between daily indoor and outdoor levels, on the one hand, and reported acute respiratory symptoms in the study population, on the other. As part of this analysis, interactions between combustion-related pollutants and allergens are being examined.

A somewhat different aspect of indoor air quality and air pollution epidemiology is be-

Figure 1 In a study of six cities, concentrations of respirable particles were monitored both (**a**) indoors and (**b**) outdoors. For each city in each graph, the data point indicates the overall annual mean concentration and the vertical line indicates the range between the monitoring site with the lowest annual mean concentration and that with the highest. Some 180 to 380 samples were analyzed to determine each overall mean value. The site with the highest annual indoor mean concentration in city 5 represents an extreme case; the second-highest site mean for that city was around 70 $\mu g/m^3$.



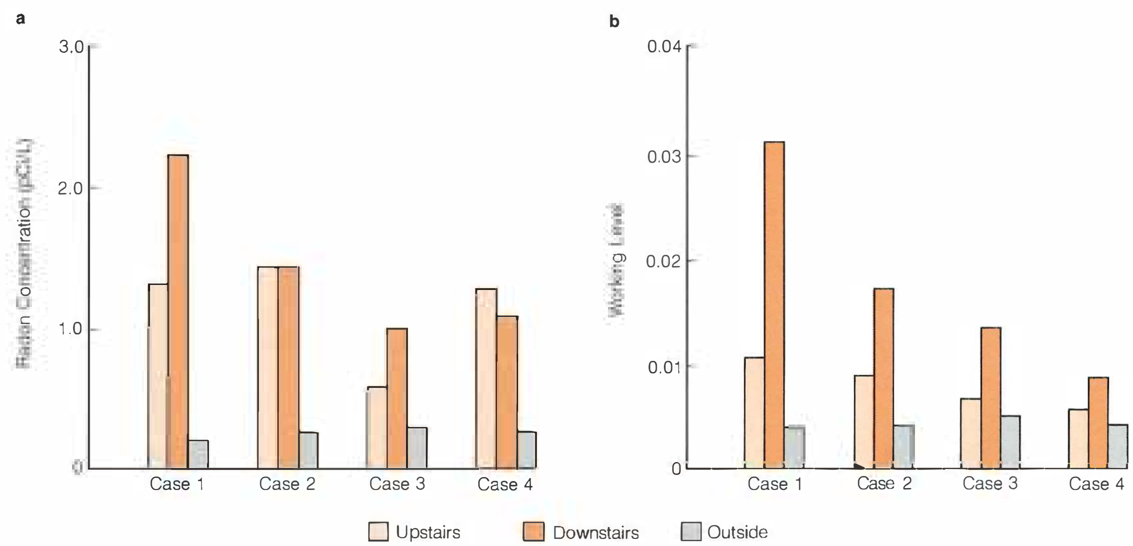
ing addressed by researchers from Columbia University, who are investigating indoor pollutant levels in residences normally sealed up in the fall and winter to prevent drafts and cold air entry. The emphasis is on low-income inner-city apartments occupied by children with asthma and their families. Because gas stoves are commonly used for cooking in the study apartments, and occasionally for supplementary heating as well, NO_2 is one of the pollutants of concern. EPRI is funding RP2265-1 to develop and test practical measures for obtaining reliable NO_2 exposure data for a future health study of the asthmatic children.

In this work daily levels of NO_2 inside and outside 88 apartments are being measured and related to daily personal NO_2 exposures as estimated by passive sampling devices worn by the occupants. Data on gas stove usage and the daily activities of the study subjects both indoors and outdoors are also being collected. Preliminary results show that in the fall and winter the study subjects are often exposed to indoor NO_2 levels exceeding the national ambient standards for outdoor air quality. Although the health effects, if any, of such indoor NO_2 exposures have yet to be determined, these findings indicate that weatherization may compromise indoor air quality.

Energy conservation measures that focus on reducing ventilation by modifying construction practices or by sealing up homes can, of course, affect the indoor levels of air contaminants other than those mentioned above. Some of these other substances are particularly interesting because they pose potentially significant health hazards that differ in nature from those usually associated with outdoor air pollution. For example, radon gas can enter dwellings from the surrounding soil, from well water, and from building materials; this raises the question of health risks from low-level ionizing radiation, specifically from indoor exposure to the radioactive decay products of radon.

Radon is one of the pollutants of interest in RP2034-1, an in-depth experimental study of the effects of weatherization on both residential energy use and indoor air quality. Geomet Technologies, Inc., is the contractor for the project, which is jointly managed by the Energy Analysis and Environment Division and the Energy Management and Utilization Division. In this study levels of CO, NO_2, formaldehyde, particulate matter, and radon were monitored inside and outside two adjacent houses of identical construction from the summer of 1983 through the 1983–1984 winter season. After an initial monitoring of indoor air quality, air

Figure 2 In an experimental house retrofitted to reduce air infiltration, researchers monitored (**a**) radon gas concentrations and (**b**) working levels, a measure of the concentration of radon decay products. Measurements were made inside and outside the house under the following conditions: case 1, circulating fan and heat exchanger both off; case 2, circulating fan operating in automatic mode (i.e., on demand), heat exchanger off; case 3, circulating fan in automatic mode, heat exchanger on (medium setting); case 4, circulating fan operating continuously, heat exchanger off. The values shown are averages based on selected summer experiments.



exchange rates, and energy use, one of the two houses was retrofitted to reduce air infiltration by 40% and equipped with an air-to-air heat exchanger. A report on the results of the study is due later this year.

An examination of initial data has already yielded some interesting findings, as illustrated in Figure 2 for radon and its decay products. The figure shows average radon concentrations and average working levels (a unit commonly used to express the concentration of radon decay products) upstairs, downstairs, and outside the retrofitted experimental house. The measurements, made with independent sampling devices, are from selected summer experiments featuring four combinations of heat exchanger and house circulation fan operation. The radon concentrations and the working levels were generally very low outdoors.

In case 1, when both the heat exchanger and the circulation fan were off, radon concentrations and working levels were higher downstairs than upstairs. In case 2, when the circulation fan operated on demand and the heat exchanger was off, radon concentrations were similar upstairs and downstairs, although working levels were still higher downstairs. The added effect of the heat exchanger, as shown in case 3, was to reduce both radon concentrations and working levels; the radon concentrations indoors were closest to those outdoors in this case. In case 4, with the fan running constantly and the heat exchanger off, radon concentrations were similar upstairs and downstairs while working levels were closest to the low outdoor value.

The preliminary interpretation of these results is that the circulation fan redistributes radon gas and tends to equalize its concentration throughout the house. By bringing in fresh air, the heat exchanger tends to equalize indoor and outdoor gas concentrations to produce the lowest indoor value. In contrast, the lowest indoor working levels occurred during continuous operation of the circulation fan without the heat exchanger. This suggests that removal of particles carrying radon decay products is more important in limiting working levels than is the reduction of radon gas concentration. *Project Managers: Cary L. Young and Robert M. Patterson*

UTILITY PLANNING MODEL

Under RP1819 EPRI has sponsored the development of a corporate strategic planning modeling system for utility use. EPRI initiated this project in response to widespread industry interest in a new type of strategic planning tool—comprehensive, integrated, flexible, and aggregated, with the ability to explore the broad and fundamental changes utilities are experiencing. Arthur Andersen & Co., the principal contractor, has recently completed initial development work on the project, including testing the prototype Utility Planning Model (UPM) and helping four utilities conduct case studies with the model. The system has been released for general utility use, and a users group is now being formed.

The need for a modeling tool

The ability of electric utilities to anticipate future trends has changed dramatically. In the past utility planners could easily predict trends in load growth and costs because these factors were very stable and consistent from period to period. Now they are much less stable, and utilities are finding it difficult to plan well in this new, uncertain business environment. There is a growing realization among utility corporate planners that they need new types of analytic techniques, including automated modeling tools, to deal with the following realities.

▫ Planning in an electric utility cannot be compartmentalized. Each aspect of planning—from the sales forecast to the production plan to the financial plan—affects all the others. Corporate planning models must be integrated and comprehensive to take such real-world interactions into account.

□ Uncertainty abounds in the new utility environment. Point forecasts and rigid plans are often too limiting; the ability to test many alternative scenarios and contingency plans is of primary importance. A relatively simple modeling tool that the user can set up and run rapidly under alternative sets of assumptions is of tremendous value in such situations. Although it cannot take the place of detailed, more precise models, this kind of tool complements them by providing an approximate but broad screening capability.

□ In a changing and uncertain environment, new problems and opportunities arise all the time. To reflect and analyze issues as they appear, a corporate modeling tool must be flexible, easy to use, and easy to modify. A modeling tool with user-friendly features is particularly advantageous in such an unstructured decision support environment.

Over the last few years interest in a comprehensive, advanced modeling system has been expressed by many planners affiliated with such bodies as the Edison Electric Institute's Corporate Planning Committee and EPRI's Utility Modeling Forum, which included participants from public and privately owned utilities. As a result, EPRI was asked to design, build, test, and demonstrate such a modeling system and to make it available to a wide range of utility companies. At the outset EPRI realized that the design and construction of a modeling system for utility planners required the cooperation and advice of those same planners. Like similar, earlier EPRI model development projects, this effort was organized around three basic groups: EPRI for project management, a principal contractor for project implementation, and an advisory structure of potential utility users for guidance and review.

To provide for maximum input from potential users, EPRI organized the advisory structure into three tiers. A large group of over 70 companies served as general observers for the project. A smaller group of 14 companies, both public and privately owned, participated much more intensively as core advisers, working closely with the contractor and EPRI in making decisions throughout the design, implementation, and testing process. Five utilities from the core group made up the third tier of the advisory structure. Commonwealth Edison Co. worked directly with the contractor on the design, coding, and testing of the prototype system, contributing computer time and the services of a full-time analyst. Four other companies conducted case studies with the prototype system, adapting it to their needs in a real-world context; these case studies will be described below. The efforts and experiences of all five utilities have served as an important critique of the project and the model.

The modeling system

The UPM simulates the entire range of utility planning activities by annual time periods up to a practical maximum of 30 years. Annual results are reported in all areas of interest to the planner, including load, revenues, production, construction, finance, and regulatory matters. Several important features of the modeling system represent innovations in electric utility analysis. The most interesting aspects of the system's conceptual and computer design are highlighted here.

First, the UPM provides a completely integrated picture of an electric utility. All modules of the system are linked and can be run only in concert: the planner must run all modules for a given year before running any module for the next year. This feature, called round-robin execution, eliminates the possibility of generating partial analyses independent of other parts and assures a complete, integrated corporate analysis.

Second, a number of optional feedback capabilities have been built into the UPM that further integrate the analysis. The most important of these are the adjustment of demand growth in response to changes in production cost and electricity price; the adjustment of system plans in response to changes in demand growth over time; and the adjustment of construction schedules for capital projects in response to changes in financial performance.

Third, the system provides a comprehensive picture of a given electric utility, both in terms of its current structure and in terms of most potential changes. The UPM represents and integrates all current planning and operating functions, including load projections, capital expansion plans, system operations, fuel supply, construction spending, customer classes and revenues, taxes, accounting, financing, and regulation. In addition, such evolving considerations as demand-side investments, fuel subsidiaries, and other nonutility businesses can be represented and consolidated into a corporate analysis. Planners can structure the system to represent multiple legal entities and/or multiple jurisidictions for utility and nonutility businesses.

Finally, the UPM has been designed and built to be a user-accessible decision support system. It has been programmed in a fourth-generation modeling language to facilitate documentation and user modification. Specialized user procedures have been designed for data entry, report writing, and graphics display. Also, a specialized internal data-handling capability has been designed. By allowing the user to expand or contract data arrays easily, this so-called "accordion" capability facilitates the addition or subtraction of variables and the modification of algorithms. All of these features make the UPM convenient, flexible, and directly adaptable to different situations and multiple issues.

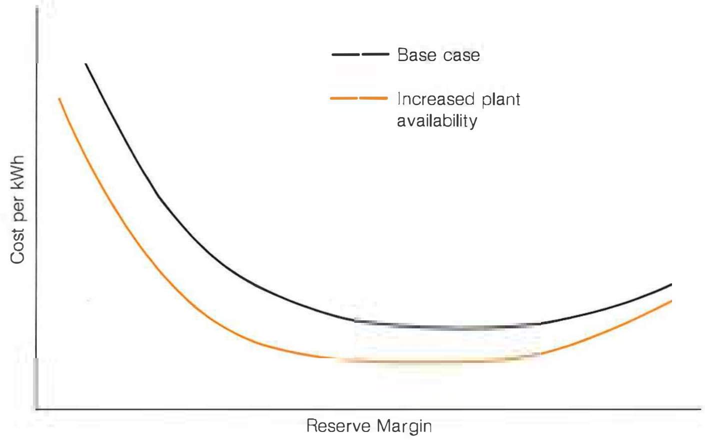
System development and user experience

The UPM is now available for general use in the electric utility industry. R&D activity proceeded through three phases. The first phase culminated in early 1982 in a detailed conceptual system design, which was approved by all project team members and core advisers. In the second phase, completed in early 1983, the project team worked with analysts at Commonwealth Edison to develop and test a prototype system. The third phase entailed utility case studies demonstrating the system's ability to address diverse issues. The project team worked with four utilities to mount, tailor, and calibrate the UPM system in-house and conduct planning studies. This phase was completed in early 1984.

The case study utilities attempted different types of exercises with the UPM and encountered different implementation issues. Wisconsin Electric Power Co. studied the question of how the promotion of load growth affects the rates paid by customers. The analysts discovered that their choice of a target reserve margin for the utility system had an important impact on the results. They used the UPM to analyze target reserve margins under various circumstances (Figure 3); this analysis provided critical input to the load growth study. The study addressed a variety of assumptions about the nature of the load growth that might be promoted, and the UPM results are being used by Wisconsin Electric Power to help prepare for a generic public service commission hearing on the issue of load growth promotion.

At Northeast Utilities the primary concern was the calibration of a satisfactory base case, particularly in terms of production costing. Because the UPM treats production dispatch in an aggregate manner and handles nonthermal resources approximately, and because Northeast operates a significant nonthermal resource on its system (a 1000-MW pumped-hydro plant), calibration became a major exercise. This effort was successful (Figure 4), and Northeast is

Figure 3 As part of a case study on the customer impacts of load growth promotion, Wisconsin Electric Power Co. used the UPM to determine least-cost target reserve margins under various system planning assumptions. The modeling results, illustrated here for the base case scenario and a scenario featuring increased plant availability, proved to be significant in examining the load growth issue.



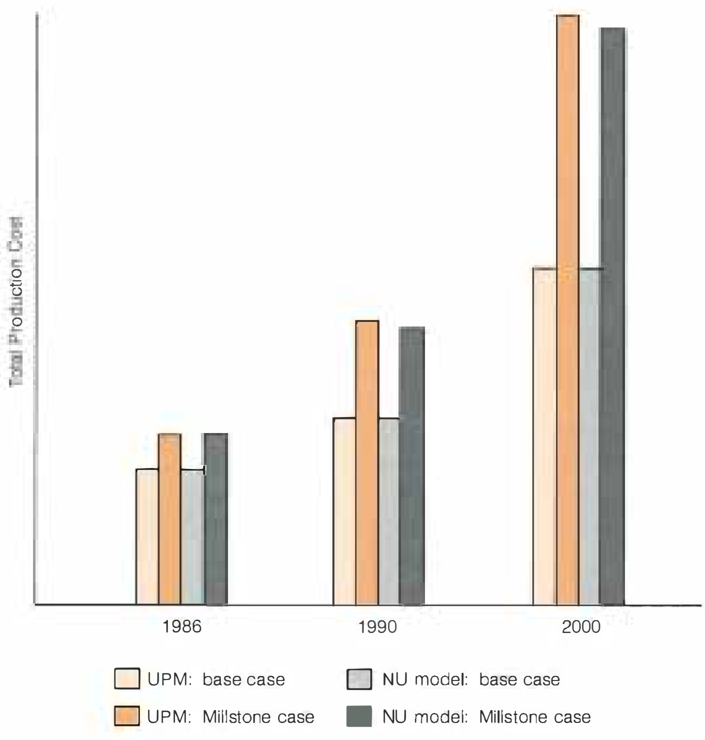


Figure 4 In a calibration exercise Northeast Utilities (NU) used its regular planning model and the UPM to analyze production costing in two scenarios—a base case and a case assuming that the utility's Millstone-3 nuclear plant was unfinished and unavailable for power generation. The close agreement between the two models' results indicates the success of the exercise.

continuing to use the UPM to study several rate base phase-in options for its Millstone-3 nuclear plant.

Analysts at Georgia Power Co. (GP) faced the task of representing several unique structural features of their system with the UPM; this exercise provided an excellent test of the UPM's flexibility. Among the characteristics modeled were the dispatching of the GP system as part of the Southern Company's power pool, GP's unique interchange agreement with its partial-requirements customers (cooperatives and municipal utilities in Georgia), and GP's extensive involvement with off-system power sales. GP is currently involved in a variety of studies using the UPM, including analyses of alternative construction scenarios and simulations of the effects of acidic deposition legislation.

Florida Power & Light Co. used the UPM in the context of long-term strategic planning. The analysts were interested in simulating the effects of a cyclic economy on the evolution and operation of their power system over time. Constructing the scenarios proved challenging because of the critical need to maintain consistency among such variables as income growth, load growth, interest rates, and inflation rates. The study was successful, and the utility is now looking at a number of alternative corporate strategies to minimize the impacts of business cycle phenomena.

Future UPM efforts

The fourth phase of this project concerns ongoing maintenance and support. EPRI intends to maintain and enhance the UPM in response to continuing user needs, primarily in four ways.

First, EPRI is supporting the establishment of a formal UPM users group to serve as a forum for information exchange and as an advisory body to suggest needed model enhancements. Second, EPRI will provide direct user support via hot-line services, orientation and training seminars, and other activities. EPRI and its contractors are planning a series of comprehensive week-long training sessions for new UPM users and hope to offer the first one this fall. Third, EPRI will fund periodic model enhancements as dictated by user needs and will be responsible for maintaining and disseminating new releases through its Electric Power Software Center. Finally, recognizing that many consulting firms assist utilities with the kinds of problems the UPM can address, EPRI is making the system available to these consultants and is encouraging its use. *Project Manager: Lewis J. Rubin*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

HYDROGEN TECHNOLOGY

*EPRI's current work on hydrogen technology under RP1086 is focusing on the near-term applications and benefits of producing hydrogen by water electrolysis. This work—which represents a significant reduction of effort from earlier chemical energy conversion activities (*EPRI Journal, *July/August 1983, p. 57)—also entails RD&D to advance water electrolysis technology. EPRI-sponsored technoeconomic assessments have determined that hydrogen production by advanced water electrolysis could benefit the utility industry through such near-term applications as generator cooling; these applications could, in turn, establish a utility experience base for the long-term integration of hydrogen as an energy carrier. This report describes utility field experience with two prototype electrolyzers, one using a solid polymer electrolyte and the other an alkaline electrolyte. The experience to date indicates satisfactory unit performance and acceptance by utility personnel. The report also reviews a recent assessment of the industrial market potential of electrolytic hydrogen in the Northeast. The study concluded that electrolytic hydrogen is more expensive than industrial bottled hydrogen and projected that in the next 10 years the growth of electricity demand in the region for electrolytic hydrogen production would be very small. Finally, the report describes a preliminary evaluation of the photoelectrochemical conversion of renewable primary energy to hydrogen and electricity and research on new approaches for water splitting.*

Prototype electrolyzers: field experience

A prototype electrolyzer based on solid-polymer-electrolyte technology was installed at a power station of Public Service Electric & Gas Co. (PSE&G) in New Jersey. During the first 14 months of operation, the electrolyzer performed satisfactorily. It required little maintenance other than the changing of cooling-water filters and the replacement of spent bottles of nitrogen, which is used to pressurize the module and to purge the system upon startup and shutdown. The system meets all performance specifications, although after a long outage a few hours of dryer regeneration with hydrogen are necessary to achieve an acceptable dew point level. Electrolysis module performance has been very consistent, with no sign of deterioration. Hydrogen samples were tested on several occasions and were found to be 99.97% pure or better.

During the 14-month period, the electrolyzer produced about 400,000 standard ft^3 (11,330 m^3) of hydrogen. About 70,000 standard ft^3 (1980 m^3) of this total was used for generator cooling; much of the time the electrolyzer was operated in a venting mode to allow personnel to perform piping modifications and solve problems with high moisture levels in the hydrogen. The electrolyzer's availability in this initial operating period was about 70% (Figure 1). The primary reason for system unavailability was the frequent breakdown of a hydrogen booster compressor that PSE&G installed to store hydrogen at 1250 psig (8.6 MPa). A variety of relatively minor problems were also encountered, including cracked solder joints, a lack of nitrogen, a defective ac power circuit breaker, and a defective sample flow pressure switch.

The electrolyzer performed particularly well during a labor strike that jeopardized outside hydrogen deliveries. Station personnel were pleased with how the on-site system increased the reliability and security of plant operations. The electrolyzer's economic benefits will be better defined at the end of the project; however, experience to date indicates that there is a strong inverse relationship between the electrolyzer load factor and the cost of hydrogen production. It appears that continuous-output, direct-feed operation coupled with simultaneous compression for storage will reduce the hydrogen production cost.

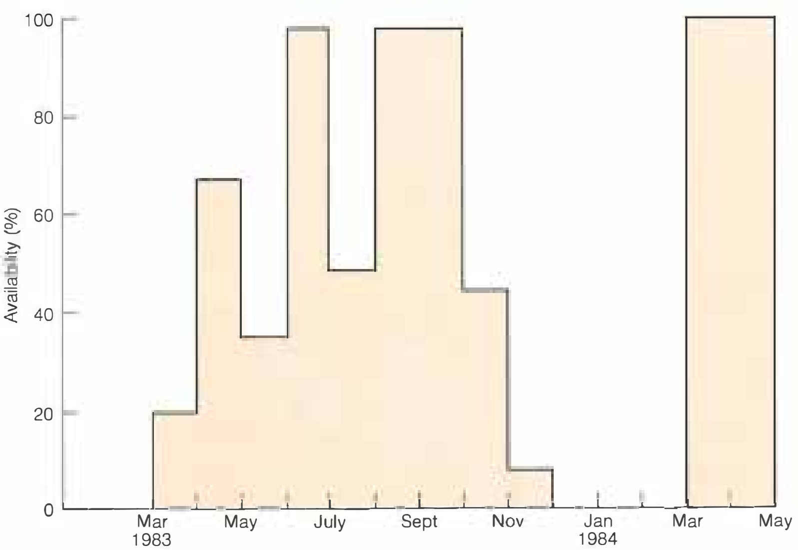
Another prototype electrolyzer, which uses an alkaline (potassium hydroxide) electrolyte, was installed at a plant of Allegheny Power System, Inc. In its first year of operation, this system produced 428,000 standard ft^3 (12,120 m^3) of hydrogen, most of which was used for generator cooling. Figure 2 shows the system's monthly availability; the field experience indicates that there are several areas for improvement in equipment reliability.

A large portion of the downtime was due to unstable operation of the differential pressure control loop. At the beginning of the reporting period, the plant lost about 22 days of availability because the O-ring seals of the electrolyte flow switches were made of a material not compatible with the electrolyte. Once identified and corrected, the problem did not recur. Two failures of the water addition controller contributed about 15 days of downtime. Intermittent failures associated with dryer regeneration caused high-moisture alarms; after the problem was identified and corrected, the system would require up to two days of operation in the venting mode before the dew point reached an acceptable level (−40°F; −40°C).

At the end of the first year of field testing, personnel determined that the cooling-water control valve and one of the dryer heater elements had failed. It is likely that some of the availability losses in the latter part of the test period were due to the deteriorating condition of the heater element.

Two changes that probably represent the most fruitful areas for reducing downtime are (1) the replacement of all needle valves with precision flow controllers, and (2) the improvement of the instrumentation circuits to permit more stable operation of the differential pressure controller and more precise fault isolation. Currently, although the problems leading to losses in availability are often relatively simple to correct, they are difficult to identify because the alarm status panel does not indicate which alarm was first. One alarm condition generally leads to others as the system shuts down; by the time an operator arrives on the scene, several alarms may be activated and the problem unclear.

Figure 1 In 3750 operating hours over 14 months, a prototype electrolyzer installed at a PSE&G plant produced 400,000 standard ft^3 of hydrogen. The availability of the unit was about 70%, and it showed consistent, satisfactory performance. Most of the downtime was due to facility problems, including an ac power breaker failure, breakdowns of an air-driven booster compressor, and the accidental failure of check valves in high-pressure hydrogen lines.



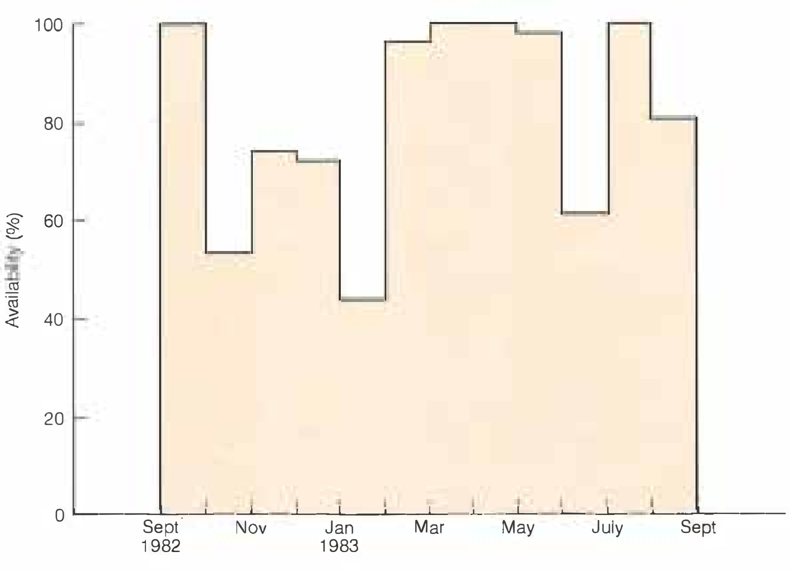


Figure 2 In 5600 operating hours over 12 months, a prototype electrolyzer installed at an Allegheny Power System plant produced 428,000 standard ft^3 of hydrogen; unit availability was about 82%. Problems with the differential pressure control loop and other control functions accounted for much of the downtime.

The operator must spend unnecessary time diagnosing what would otherwise be a simple problem to correct.

Industrial market potential

Results from an earlier study (EPRI EM-1154) indicated that electrolytic hydrogen can be produced at competitive cost for demands of up to 100 million standard ft^3 (2.8 million m^3) per year. Using a previously developed methodology, The Futures Group investigated the site-specific potential demand for electrolytic hydrogen in the service areas of three northeastern utilities: PSE&G, Niagara Mohawk Power Corp., and Northeast Utilities. Two major suppliers of industrial hydrogen—Linde Division of Union Carbide Corp. and Air Products and Chemicals, Inc.—provided current hydrogen consumption data and projections for the same territory.

The results (reported in EM-3561) indicate that in these three service areas, electrolytic hydrogen would have limited success competing with bottled hydrogen. The large industrial hydrogen plants built only a few years ago still have excess production capacity. As a result, industrial hydrogen prices did not escalate during 1979–1983, and bottled hydrogen today costs less than hydrogen produced by water electrolysis. This finding is contrary to the earlier conclusions of EM-1154. Other factors that are responsible for making electrolytic hydrogen less attractive than bottled hydrogen are the following.

- The high installed cost of electrolyzers, as much as $2700/kW for a hydrogen output of 1000 standard ft^3/h (28 m^3/h; 100 kW equivalent)
- The relatively high cost of electricity in the Northeast, as much as 60 mills/kWh
- Poor plant utilization (about 50% or less) among industrial hydrogen users because of deteriorating economic conditions
- The high cost of capital (about 20%) experienced by industrial plants

The cost analysis indicated that capital charges dominate the production costs for small on-site electrolyzer facilities, making up as much as 60% of the total cost. In addition, small users would not benefit from low-cost off-peak power: the savings afforded by its use would not be sufficient to pay for the necessary high-pressure hydrogen storage equipment. Even when compared with electrolytic hydrogen from large-scale operations (10,000 standard ft^3/h, or 283 m^3/h; 1000 kW equivalent), bottled hydrogen was 10% cheaper.

The industrial processes studied in the three service areas could potentially consume 140 million kWh/yr of electricity for electrolytic hydrogen production; this might expand in the next 10 years to 240 million kWh/yr. These low estimates indicate that the initial market penetration and growth of electrolytic hydrogen will be slow. However, in a few pockets of the United States, the availability of excess low-cost baseload capacity and energy could enable utilities to benefit from producing electrolytic hydrogen for a large user. EPRI has contracted with Stone & Webster Engineering Corp. (RP1086-18) to perform a feasibility study that will scope the economics for a standalone electrolytic hydrogen facility using commercially available large-scale electrolyzers from vendors in the United States, Canada, and Europe. The study will evaluate the plant design, the commercial readiness of each technology and its sensitivity to the cost of electricity, and various financial parameters.

The reference design used for technoeconomic comparison will be further developed for a site-specific application to validate the electrolytic hydrogen plant design and its competitive position. In this study the electrolyzer will be assumed to provide liquid hydrogen and liquid oxygen for the National Aeronautics and Space Administration's Kennedy Space Center.

Long-term hydrogen research

The conversion of renewable primary energy to electric and chemical energy is an attractive option for utilities. Photovoltaic systems are being researched for converting sunlight to electricity and/or such storable fuels as gaseous hydrogen. Although the real payoffs are some years ahead, utilities may derive considerable technological benefit from exploring these photon-driven concepts for producing storable fuels for power generation.

Under RP1086-16 EPRI is supporting work at the Fundamental Hydrogen Research Center at Texas A&M University to explore advanced methods of hydrogen production from sunlight that use optimized photovoltaic and/or photoelectrochemical devices. Multiphotojunction devices with optimally matched current density characteristics may be capable of producing hydrogen and oxygen from water at better than 20% efficiency. This compares with present efficiency values of 3% for twin thin-layer tandem amorphous silicon cells—so-called $(pln)^2$ cells—and 7% for paired (n-p/n-p) single-crystal gallium arsenide cells with catalytic surfaces.

The Hydrogen Research Center is funded by the National Science Foundation and industrial organizations to maintain the competitive edge of U.S. hydrogen technology through industry-university collaboration in long-term research. In addition to EPRI's photoelectrochemical research project, the center's staff is examining advanced methods of lower-cost hydrogen production, such as Faraday disk homopolar electrolysis, pulsed electrolysis, and electrolysis with an anodic depolarizer. These activities are complementary to EPRI's hydrogen technology program.

Other methods of producing hydrogen have been suggested from time to time, and one of EPRI's roles is to ascertain for its member utilities whether these methods are viable. As part of this effort, EPRI entered into an agreement (RP1086-15) with Lawrence Berkeley Laboratory (LBL) to conduct a laboratory test of the SLX process, which was developed by Omnia Research, Inc. Under RP1086-14 the developer loaned an SLX prototype unit for independent testing. LBL was asked to collect test data on mass and energy balance for an extended period of time to determine hydrogen production efficiency.

The SLX unit underwent 12 weeks of checking and tuning by Omnia staff before being turned over to LBL personnel for an extended test run. During 12 hours of a single proof-of-concept test using external purge hydrogen, LBL carefully monitored the energy, mass, and composition of all the machine's input and output streams. The data conclusively indicated that no net production of hydrogen occurred during the test period. *Project Manager: B. R. Mehta*

HIGH-HEAD PUMP-TURBINE DEVELOPMENT

High-head pumped-storage plants, both conventional and underground, offer the utility industry a practical and economical means of providing peaking generation, system regulation, and spinning reserve. These storage plants can efficiently and cost-effectively compensate for the slow response and high cycling costs of thermal plants. As well as rapidly responding to utility system load changes, they can replace oil-fired intermediate and peaking units. The result is the conservation of financial and nonrenewable fuel resources. The availability of high-head pump-turbines will be critical to the technoeconomics of underground pumped storage, which will become an important alternative to conventional (aboveground) storage as environmentally acceptable aboveground sites become scarcer. Thus EPRI initiated a project to design and develop a high-head regulatable multistage pump-turbine and to evaluate its feasibility and performance (RP2039).

Pump-turbine requirements

Enhanced environmental acceptability and a broader siting capability are two advantages of a pumped-storage plant whose lower reservoir is located in an underground cavern. However, such plants require heads (subsurface depths) of 5000 ft (1500 m) to be economical, according to detailed studies by Potomac Electric Power Co. that involved the design, costing, and evaluation of an underground pumped-hydro generation facility. These high heads result in reduced reservoir sizes and, therefore, costs.

The maximum head for the single-stage reversible Francis turbine, which is the type selected by U.S. utilities as most practical for pumped-storage service, is in the range of 800–900 m. To go beyond these heads, it is necessary to use a multistage runner that effectively prorates the head to each stage. Thus a head of 1500 m can be attained within the state of the art of turbine design and operation by using a two-stage runner, which limits the head per stage to 750 m.

Because existing multistage reversible pump-turbines cannot be regulated, they are unable to provide for load following, spinning reserve, or load regulation. In most utility systems these services contribute significantly to the economic attractiveness and operating usefulness of a pumped-storage plant. An alternative but more expensive scheme is to use regulatable single-stage reversible machines that could reach the 1500-m head in two successive drops. However, the resulting complexity of underground tunnel and storage cavern construction would add to plant costs, and the operation of two units in series would materially reduce availabilty.

In response to the need for a high-head regulatable multistage pump-turbine, EPRI established a development project with Hydraulic Turbines, Inc. (HTI), a joint venture of Hitachi, Ltd., and General Electric Co. The approach was to develop and evaluate a hydraulic turbine design in the same way a manufacturer would upon receipt of a commercial order for conventional turbine machinery. The general design parameters were patterned on a site investigated by Commonwealth Edison Co. that required a head of 1500 m and a generator output of over 600 MW.

The design feature that makes the resulting two-stage reversible pump-turbine different from the multistage reversible units already operating in Europe and Asia is its movable wicket gates. These gates regulate the water flow into the unit, which results in a rapidly adjustable turbine output—an important characteristic of both conventional hydroelectric generating units and U.S. pumped-storage plants for meeting rapid changes in load.

Development and evaluation

Meeting the ultimate project goal—to ensure the commercial availability of a two-stage reversible pump-turbine with regulatable wicket gates for the 1500-m head range—involved a series of development and evaluation efforts, including the confirmation of high efficiencies and trouble-free operation. The project was divided into these stages and tasks.

- Preliminary design: baseline machine description, hydraulic design, mechanical design, component layout, structural design, and projection of performance characteristics
- Advanced design by analysis: theoretical finite-element studies, detailed component design, and evaluation of manufacturing methods and materials—together to result in a complete, ready-to-build design
- Model design and construction: fabrication of a scale model according to standard industry practices
- Model testing: prediction of prototype performance characteristics, determination of efficiencies, and evaluation of cavitation performance
- Design finalization based on the results of model testing
- Confirmation test planning: definition of a comprehensive model test program to demonstrate conclusively to the utility industry the viability of high-head pump-turbine machinery

Hydraulic performance and characteristics

One of the first and most important design decisions was selection of the operating speed. The speed chosen was 720 rpm (considerably faster than that of equipment in existing U.S. pumped-storage units). Higher-speed machines would be subject to greater cavitation damage, greater vibration, and lower safety factors; lower-speed (larger-diameter) machines would have lower efficiencies and narrower waterways, which would make it much more difficult for workers to maneuver inside and perform the surface machining required to minimize cavitation for high-head turbines.

The projected specifications of the prototype pump-turbine were based on tests of a reduced-scale (6.5:1) hydraulic model (Figure 3). The pump-turbine will produce 655 MW at maximum head and 610 MW at minimum head, with a discharge of 53 m^3/s (1860 ft^3/s) and 52 m^3/s (1825 ft^3/s), respectively. The highest efficiency occurs at a machine output of 595 MW, slightly less than the maximum output of 655 MW; thus the overload factor is 1.10 (655/595). Synchronous operation of the top- and bottom-stage wicket gates, as opposed to operation with fixed bottom-stage gate positions, improves efficiency and vibration characteristics.

The pump performance characteristics show a discharge of 40 m^3/s at minimum head and 37.1 m^3/s at maximum head (a decrease of only 7%), with a pump input of 660 MW and 632 MW, respectively. The efficiencies determined from the model tests are comparable with those of currently available single-stage reversible units. Converted to prototype scale, the efficiency of this two-stage unit at maximum turbine head is 90.4%. The pumping efficiency of 90.6% is comparable with that of 500-m-class single-stage machines (90–91%).

Design and mechanical aspects

The two factors with the greatest impact on HTI's design and manufacturing approaches are the high head and the relatively small size of the machine. Because of the machine speed and the high head, the runners are only 3.2 m in diameter for a machine with an output of over 600 MW. Similar-capacity machines at a lower head and speed at Grand Coulee Dam have runner diameters of

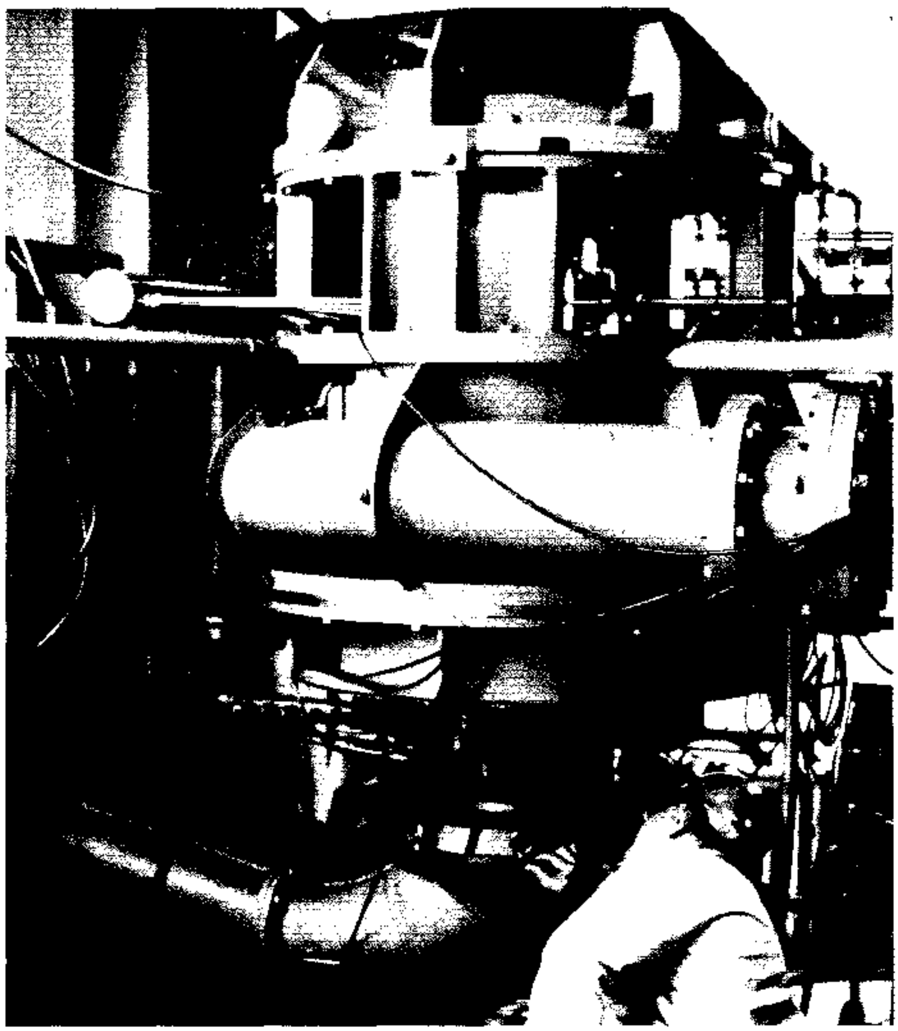


Figure 3 Tests were conducted on this reduced-scale reversible pump-turbine to determine performance characteristics and efficiencies. EPRI undertook the development of this regulatable two-stage machine in response to the high-head requirements of underground pumped-hydro plants.

nearly 10 m. The high head and the machine speed also lead to a substantially greater potential for cavitation damage, which must be mitigated by design, choice of materials, machining, and unit submergence.

Several features were designed to meet the challenges associated with the head and the potential for cavitation damage.

- Use of high-quality, commercially available stainless steels for major movable parts that are subjected to high pressures

- One-piece casted runners and a separate shaft for each runner

- A radial-faced seal for the upper shaft and conventional seals for the wicket gates and the lower shaft

- A two-piece (inner and outer) return guide, each piece having 16 vanes for guiding flow between runners

- A unit submergence (i.e., the distance of the unit below the tailwater level) of 125 m, which was selected on the basis of model tests showing that pump cavitation would begin only at submergences significantly less than 125 m

Given the complexity of the machine, with its two stages of runners and wicket gates, HTI estimates an installation time of 41 months: embedded components, 20 months; nonembedded components, 15 months; and startup, 6 months. Under ideal conditions this time might be reduced to 30 months. The schedule is longer than that for conventional single-stage machines, and long lead times will be a major impediment for this technology just as for conventional pumped storage. However, for underground pumped storage, the critical path will likely be the excavation time for the lower reservoir rather than the turbine installation time.

Confirmation testing

Recognizing that the model does not represent the prototype with regard to speed, size, and head, HTI proposed several approaches for confirming the model tests should that become necessary. The proposed tests are aimed at a more comprehensive evaluation of cavitation damage, fatigue strength, dynamic behavior, and seal performance. They include full-pressure tests on certain components, ultra-high-speed tests on a smaller model, and full-head tests on a larger model.

Going much beyond the model testing already conducted promises to be expensive, however, and such confirmation testing should focus on the issues of concern to the first buyer(s). These issues remain undefined, since the reduced need for new capacity and the financial issues associated with large plants have discouraged potential buyers. When this situation changes, EPRI will provide technical assistance to member utilities seriously considering either underground pumped hydro or high-head conventional pumped storage.

It is possible that further confirmation tests will not be necessary. First, the design and material concepts intended for the high-head pump-turbine do not depart substantially from the state of the art. While their combination results in a unit that far exceeds existing head and capacity, individually these concepts have worked in commercial machinery. As a result, existing equipment performance, along with the model tests conducted in this project, should be sufficient for confidently predicting prototype behavior and performance. Second, the model testing in this project was extremely successful: the results accurately represented projections from analytic modeling, and an independent expert selected by EPRI to observe the testing confirmed it to be objective and accurate. In fact, the results from the present model tests have been sufficient for Hitachi to offer its machine as a commercial product. The results of this design, development, and test project should encourage the consideration of prototype two-stage pump-turbines as a practical means of expanding the potential of pumped storage in the United States.

For the first utility to order the equipment, Hitachi will provide a warranty that is substantially better than conventional warranties: the company has added an additional year to the usual warranty period, making it five years after delivery or three years (or 8000 hours) of operation, whichever occurs first. This extended warranty is a statement of confidence as well as a willingness on the part of the manufacturer to share the risks with the first utility to develop a site requiring the high-head pump-turbine.

This project to develop a regulatable pump-turbine for a 1500-m head has moved the technology from a conceptual configuration to a commercial product. The new product doubles the head capability of state-of-the-art turbines while retaining the use of commercially available materials and design concepts as well as accepted manufacturing processes. *Project Manager: Antonio Ferreira*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

SEISMIC HAZARD ANALYSIS

A major issue of current interest to utilities is the characterization of seismic hazards at power plant sites, which involves examining the seismic design ground motion in terms of the probability that it will be exceeded in a specified time interval. In response to a recent change of position by the U.S. Geological Survey, the Nuclear Regulatory Commission (NRC) is sponsoring a study by the Lawrence Livermore National Laboratory to establish uniform hazard spectra for all nuclear plants east of the Rocky Mountains. The study's draft report suggests that selected sites in the eastern United States should have a higher seismic design basis than originally considered. Some reanalysis based on evolving technology and related requalification may be deemed desirable. To give the industry a strong technical background and a basic seismic hazard methodology, EPRI is conducting extensive research on seismic hazards, including basic research on earthquake causes in the eastern United States under an owners group program (P101). EPRI has also sponsored work with the Yankee Atomic Electric Co. to formalize and document both a historical methodology and a seismic source methodology developed by Yankee and its consultants. The objective is to produce computer codes, code documentation, and sample applications that utilities can use for either a simple best estimate of the probability of earthquakes above a given magnitude (the seismic hazard curve) or a complete, weighted family of curves for input to a probabilistic risk assessment (PRA). This status report reviews these efforts.

Under RP1233-10 a method of seismic hazard analysis using historical earthquake data was documented, programmed for computer calculation, and published as an interim report in May 1984 (EPRI NP-3438). The report describes the EPRI computer code EQHIST and contains a user's manual. This methodology is particularly useful for estimating seismic hazards at a site at probability levels of 0.1 to 0.001 per year. Its primary advantage is that the analysis requires fewer assumptions than other methods.

The historical approach assumes that known past earthquakes provide a representative sample of a continuing sequence (i.e., that, in general, future earthquakes will occur in approximately the same location and with the same frequencies and magnitudes as those in the past). This approach is statistical and is based directly on the earthquake catalog of historical events.

A second report is being prepared that documents a multiple-hypothesis computer code for seismic source hazard analysis, as well as methodological procedures for determining input parameters. The seismic source approach seeks to extend the hazard methodology to probability levels less than 0.001 per year, normally required for the assurance of reactor safety. NRC currently uses the deterministic approach of Appendix A to 10CFR, Part 100, which results in estimates of earthquake effects that a site may be subject to under a given set of geologic conditions (e.g., a given magnitude at a given distance). The regulation provides a logic framework for estimating seismic design ground motion and can be applied when one has an adequate understanding of regional earthquake causes. Unfortunately, the causes of earthquakes are poorly understood, especially for the eastern United States.

The seismic source methodology attempts to use knowledge of both the basic causes of earthquakes and historical seismicity to define seismic source zones with homogeneous seismicity parameters. This information is analytically and/or numerically integrated to estimate annual probabilities of exceedance for various parameters of interest (acceleration, velocity, spectral velocity, and so on) at a specified site. The methodology has a number of underlying assumptions.

- A region has homogeneous earthquake source zones—that is, zones within which the seismicity (the temporal and spatial occurrence of earthquakes) is represented by a single process. Each source generates earthquakes at random times, at random geographic locations within the source zone, and with random magnitudes, and each can be fully described by a seismicity model.

- The truncated exponential distribution (magnitude model) represents earthquake sizes.

- The effect at the site of an earthquake of a given magnitude and a given epicentral distance is a random variable dependent on the magnitude and the distance. The dependence is specified by an attenuation model.

- The seismic hazard at the site (e.g., the mean annual rate at which ground motion of a given intensity is exceeded) is obtained by adding the mean exceedance-rate contributions from all sources. The probability of exceeding the ground motion during a given time interval is then calculated under the assumption of Poisson events in time.

Because many input variables—such as zone, recurrence, and attenuation parameters—are uncertain, a single hazard curve cannot fully describe the uncertainty on estimates of the seismic hazard at a site. Several strategies are available to determine the effect of uncertainty on the seismic hazard results. By far, the most popular strategy has been the sensitivity analysis, which has been used in many past seismic hazard studies. Sensitivity methods involve assigning incremental values for input parameters (e.g., maximum magnitude) and rerunning the program to determine the change in the hazard results. The value of this increment does not necessarily reflect the degree of uncertainty in the parameter. The sensitivity study only shows a parameter's influence on the results per given parameter increment. The reviewer must then determine how to use all these results.

The input required by modern seismic PRAs, along with the frequent requests of decision makers and regulators for quantitative statements of uncertainty in low-probability hazard estimates, has made necessary the development of a methodology to analyze and display the results of multiple seismic hypotheses. The result is the computer program EQZONE, which automatically handles alternative hypotheses about the models (maps) of the homogeneous zones, the attenuation model, mean activity rates, and upper-bound magnitudes. Because thousands of hazard curves may be generated, the program incorporates a grouping routine to present the results either in a small number of representative curves for input to a PRA or in a more traditional form. The program has been completed and a user's manual is being prepared.

An advantage of the multiple-hypothesis program is that experts can define consistent hypotheses and, on the basis of their experience and the data, can determine a weight (probability) that defines their belief in an individual hypothesis. A disadvantage of this methodology is that it requires an exhaustive set of hypotheses, ranging from the credible to the nearly incredible; the result is an extremely large number of hazard curves. But once the analysis has been completed and all possible alternatives have been addressed, subsequent assessments of seismic hazard will simply involve changing the weights applied to the alternatives. In this way the seismic hazard can easily be updated with future information.

Additional work has been completed in estimating input parameters for the seismic source multiple-hypothesis program. This work has established a statistical procedure for calculating seismic parameters (e.g., activity and rate) for given source areas. To obtain unbiased estimates of these parameters, one must account for incomplete historical earthquake data (i.e., not all the earthquakes that have occurred in the time interval and in the geographic region covered by the catalog are actually listed in the catalog) and, to a lesser extent, for clustering of earthquakes in time and space. A procedure to make allowance for incomplete catalog data has been developed and applied to a region in the northeastern United States. Work has also been completed on a method for developing attenuation models to cover areas, such as the Northeast, where quantitative ground motion data are limited. *Project Manager: David Worledge*

LWR COOLANT IMPURITY CONTROL

As anyone knows who has seen cars in cities that use salt to cover icy streets, salt water accelerates corrosion. The same phenomenon can take place in the water coolant and steam systems of nuclear and fossil fuel power plants. Because water in power plants is much hotter than that on a city street, a lot less salt is required to corrode expensive components. EPRI is working on six approaches to combat coolant impurity: (1) monitoring plant water and steam impurity species, (2) correlating impurity species with corrosion damage events, (3) preventing impurity entry with high-integrity interfaces between outside cooling waters and cleaner plant waters, (4) removing impurities that enter the system, (5) treating coolant with additives to reduce the corrosive effects, and (6) determining impurity transport properties to avoid damaging concentrations. This report will cover EPRI projects on plant monitoring, impurity removal, additives, and transport properties. The projects reviewed have been coordinated with, but are separate from, efforts of a similar nature sponsored by the Steam Generator Owners Group. Related projects specifically aimed at controlling BWR pipe cracking were reported in the June 1984 EPRI Journal *(p. 58).*

Plant monitoring

Monitoring the presence and movement of chemical impurities at any power plant, fossil fuel or nuclear, is becoming increasingly important. Submicrogram per liter (ppb) concentrations of these impurities can accumulate in kilogram quantities in steam generators or turbines. These impurities, in concentrated liquid form, are thought to cause corrosion of steam generator internals and initiate cracking in turbine components. Impurities and the damage they cause result in component failure and plant shutdowns. The replacement of one turbine rotor can cost more than $10 million.

The need to monitor power plant water/steam systems is clear. Unfortunately, instruments that would satisfy plant monitoring needs have not been available until recently. Although continuous analyzers based on specific ion electrode systems have been available for a number of years, they have not yet won the confidence of many utility users for measurements at very low concentrations. Conductivity meters are also widely used but are difficult to calibrate in the region needed by utilities. These analyzers do not identify offending ionic species; thus the sources of an impurity may be difficult to trace.

EPRI has supported the development and demonstration of an instrument capable of filling these needs: an on-line, automated ion chromatograph. This device can semicontinuously analyze water from up to 10 sample locations throughout a secondary water/steam system.

On-line water sampling is achieved by diverting a small flow (1–5 mL/min) from a high-flow-range (1-L/min) sample line into a Teflon reservoir, where the water accumulates until the instrument control computer selects the reservoir for analysis. The samples are injected into ion chromatographs. Chemical separation in these units results in the analysis of anions (e.g., chloride, nitrite, nitrate, orthophosphate, sulfate, and oxalate), monovalent cations (sodium, ammonium, and potassium), and divalent cations (magnesium and calcium). Work is under way to extend this list. This scheme provides a continuous average sample that is analyzed by a noncontinuous measurement method.

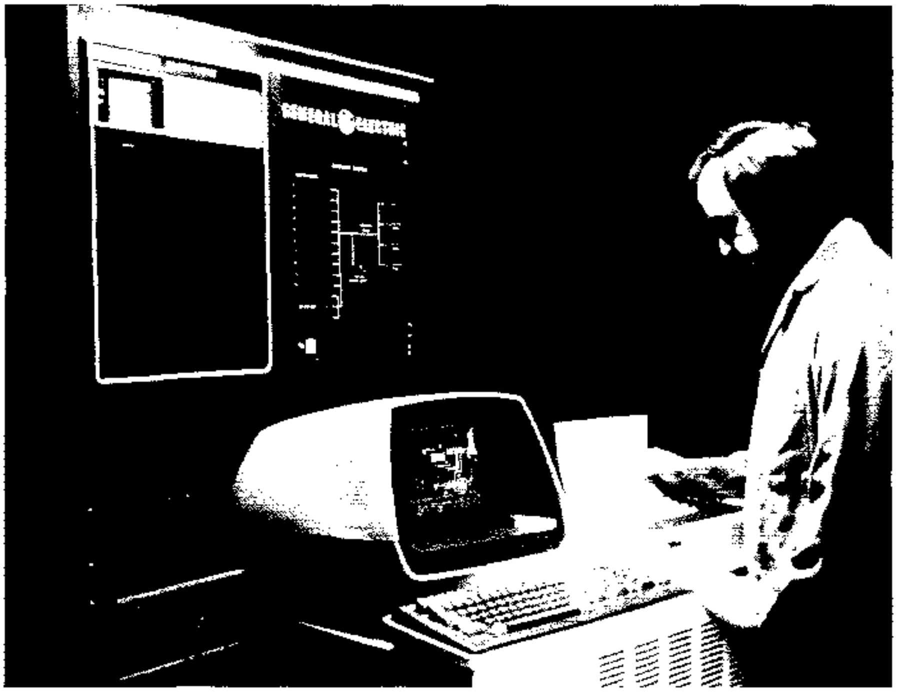
These chromatographs have been installed and operated at three PWR plants, Rancho Seco, Calvert Cliffs, and McGuire. Several months of semicontinuous monitoring has resulted in two main surprises: sulfate (SO_4^{--}) ions are less readily polished from condensate than sodium (Na^+) and chloride (Cl^-); and sulfate ions appear to be much more volatile in steam than sodium and chloride ions.

Similar instruments have been found to work well on BWR water, steam, and feedwater circuits. At these plants oxalate is appearing along with the more usual sulfate and chloride.

Ion chromatographs are ready for plant installation. They substantially upgrade plant on-line chemical monitoring capabilities. General Electric Co., the EPRI contractor under RP1447-1 who developed the automated ion chromatograph, is now marketing the instrument under EPRI license, using the trade name Iontrac (Figure 1). Less automated laboratory versions of the instrument are available from Dionex Corp., which holds the patent on the key process in ion chromatography.

Measuring individual impurities is one monitoring approach. Another is to measure the net corrosive effect, which has been related to two main variables—the pH (acidity) and the corrosion potential—in many labora-

Figure 1 Ion chromatograph for the measurement of water/steam impurities at the sub-ppb level in nuclear and fossil fuel power plants.



tory corrosion tests over the past two decades. Because these variables change with temperature, the usual procedure of sampling power plant water by cooling it first will not work. The instrument must perform at full operating pressure and temperature. For nuclear plants the maximum pressures and temperatures are 15.4 MPa (2200 psi) and 315°C (600°F).

Investigators have designed and tested several probes to measure these variables, as well as the dissolved-hydrogen content (RP1168-1). It has proved difficult to construct a wide-range pH meter because the probe itself must be able to withstand corrosion under acidic conditions. Testing of the probes is planned at Florida Power & Light Co.'s St. Lucie plant and Portland General Electric Co.'s Trojan plant. Using similar technology, the electrochemical potentials of the main system alloys have been measured extensively at the Vermont Yankee BWR (NP-3521).

Impurity removal

Despite a utility's best efforts, salts can enter the system through cracks in the condenser and through the makeup water (which is usually added at about 1% of the main coolant flow). Research on improving the impurity removal process includes efforts to increase the efficiency of condensate polishing demineralizers. Under RP1571-5 investigators are analyzing the costs and benefits of utility decisions to improve existing systems or to retrofit with a technically better one. Current evidence indicates that a two-bed system would best serve the PWR steam-producing side. The first bed would remove the ammonia (NH_3) added for pH control (positive or cations only), and the second would remove both positive and negative salt impurities as a mixed cation-anion deep-bed polisher. European utilities use this system widely in both fossil and nuclear applications, and Southern California Edison Co. is currently building two for its San Onofre Units 2 and 3.

Two in-plant monitoring projects (RP1124 and RP1447-1) pinpointed the polishing system as a potential source of impurities, chiefly sulfate ions, under some operating conditions. Other conditions allowed significant chloride and sodium ion leaks. A number of EPRI projects managed by the Steam Generator Project Office also address the ion removal problem, particularly resin quality, regeneration procedures, and resin leak factors.

Work on condensate polishers and the sulfate ions has already produced these significant findings.

- Inadequate rinse time allows sulfuric acid (H_2SO_4), used to regenerate cation (positive ion) resins, to enter the system water just after a regeneration.

- Because sulfate ion diffusion out of the resin bead is relatively slow, waiting 24 hours after regeneration allows much faster rinse and eliminates ingress.

- A sulfonate group holds the positive ions in the cation ion exchange resins. When cation resin beads leak into the steam-generating system, the sulfonate groups are effectively boiled off the beads, becoming sulfate ions indistinguishable from sulfate from other sources.

- Once sulfate has entered the circuit, it appears to be far more volatile than a salt (say, Na_2SO_4). Its properties seem to be more like those of sulfuric acid, and it goes with the steam more than a salt would.

- Going around the circuit and back into the condenser hot well in the steam, the sulfate ion is very likely to pass through the condensate polisher unless the flow rate per unit area is slow and/or the resin is relatively new or unfouled by organics.

All these features make sulfate a potentially dominant impurity species. Whether it is also a major corrosion concern is yet to be fully confirmed. The first revision of the PWR secondary water chemistry guidelines, now in preparation, will almost certainly include sulfate.

The major surprise effect seen so far in BWR systems is the appearance of oxalate ions. In normal operation a BWR core is a very oxidizing environment; that is, the entering nitrogen oxidizes to nitrate. Apparently two-carbon organic fragments entering the BWR are being oxidized to oxalic acid ($H_2C_2O_4$), an effect so far not seen in a PWR's reducing environment. The two-carbon fragment may be the result of radiolytic or thermal degradation of ion exchange resin from condensate polishing demineralizer beds. The evidence for this explanation is that oxalate and sulfate go through similar transients versus time, and two-carbon vinyl (CH=CH) groups are major links between adjacent benzene rings in the resin polymer.

Additives to mitigate impurity effects

Even pure water can dissolve the oxides of metal alloys. Thus in many systems, especially the PWR steam-producing system, additives are used to raise the pH one to three units above neutral to decrease oxide solubility. Ammonia, morpholine (C_4H_9NO), and cyclohexylamine ($C_6H_{14}N$) have been used for this purpose, ammonia by far most commonly. The latter two bases are less volatile. Even less volatile amines are now being sought under RP1571-3 for the following reasons.

- Ammonia becomes less basic as the temperature rises, even in single-phase liquid water (e.g., along the feedwater train before the steam generator in a PWR).
- Ammonia cannot neutralize corrosive acids produced in steam generator crevices because it is stripped into the steam phase so readily during the boiling process.
- As steam loses energy in driving the turbine and condenses, liquid water droplets form that are corrosive to carbon steel piping unless the pH is raised. Ammonia again fails to neutralize this corrosive liquid because of its tendency to remain in the steam phase.

After screening several thousand possible compounds to find a stronger, less volatile base than ammonia, the contractor, San Diego State University, has selected quinuclidine ($C_7H_{13}N$) for further tests. This or some better base yet to be identified may help reduce iron and copper release in the feedwater heater train, corrosion in steam generator crevices, erosion-corrosion in wet steam piping, and acid-caused cracking of low-pressure turbine disks. The application of such bases is not expected to produce troublesome side effects because similar compounds—for example, morpholine—are widely used without major problems. The thermal decomposition of bases like quinuclidine will probably be quite similar to that of morpholine. Electricité de France has recently converted most of its over 30 PWRs to morpholine to reduce erosion-corrosion in wet steam piping.

Transport properties

Because low-pressure turbine disk cracking has often been associated with steam impurity deposits, EPRI initiated several projects to address this issue (RP969-1; RP1068-1, -4; RP1124-1, -2, -3, -4). Sodium hydroxide, or caustic (NaOH), was studied first because it was thought to be the primary culprit. When steam is generated, most of the salts stay behind with the liquid water phase. However, as its temperature increases, steam is increasingly able to carry truly dissolved salts (i.e., salts that are not merely particulates or liquid droplets). Conversely, as steam cools on its trip through the turbine, the dissolved materials tend to deposit like snow from cooling moist air. These dry salts do not corrode; however, when they dissolve again in liquid, they become corrosive. Hence the dry-wet transition zones in the low-pressure turbine show a preponderance of the corrosion/cracking damage.

EPRI research (RP1068-1) showed that the concentration of sodium hydroxide below which deposition is avoided in PWR low-pressure turbines near the dry-wet transition (Wilson line) is about 0.5 ppb. Similar work on sodium chloride (NaCl), the second most highly suspected corrosive impurity, showed that its deposition limit is only 0.004 ppb (RP969-1).

Because chloride appears in turbine steam well above this limit, other chloride-containing molecular forms are suspected to be the transporting species. The most likely is volatile hydrochloric acid (HCl). Work at Babcock & Wilcox Co. under RP1068-1 showed that one probable way sodium chloride ingress produces hydrochloric acid in the steam loop is the thermal decomposition of ammonium chloride (NH_4Cl) in any dryout region. The most likely dryout region upstream of the turbine is at the superheated portion of the moisture separator/reheater. Hence the researchers simulated this region in a series of experiments showing hydrochloric acid production by thermal decomposition of ammonium chloride. Because the ammonia concentration is always 10 to 1000 times that of the sodium, ammonia's properties will dominate over those of any other positive ion present. Hence the transport properties of any negative ions coming into the region, such as sulfate or chloride, will be dominated by their ammonium salts regardless of the positive ion associated with them as they enter the circuit.

Before the EPRI research, steam purity limits were generally set for sodium alone. Now it appears prudent to set limits on sulfate and chloride as well. EPRI research indicates that the concentration limits for the longest feasible turbine operation should be in the range of 0.1–0.5 ppb until more crack-resistant alloys or lower-stress-level turbine designs are in wide use. Other research projects (RP1398 and RP1929) seem to indicate cracking can still occur under the influence of ultrapure water, although at a much reduced rate than in less pure water. *Project Manager: Thomas Passell*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP1525-5	Continuous Mechanical Scale Removal	3 months	97.3	Heat Exchanger Systems, Inc. *J. Bigger*
RP1654-24	KILnGas Engineering Support Services	4 months	52.4	Radian Corp. *M. Epstein*
RP1656-2	Methanol Catalyst Preparation	5 months	36.1	United Catalysts, Inc. *N. Hertz*
RP1671-5	Systems Integration Design for Hybrid Power Plant at Pleasant Bayou	4 months	41.5	The Ben Holt Co. *E. Evans*
RP1799-12	Utah Coal Test Run on TVA's Texaco Gasification Pilot Plant	7 months	100.1	Tennessee Valley Authority *N. Holt*
RP1971-14	Evaluation of Engineering Opportunities on Existing and Planned Fusion Facilities	11 months	42.9	Department of Energy *R. Scott*
RP2029-12	Off-Design Operation of Gasification–Combined-Cycle Systems	24 months	176.4	Stanford University *M. Gluckman*
RP2029-15	IGCC Plant Output Capabilities for RAM Analysis and Part-Load Performance Estimates	8 months	98.0	Fluor Engineers, Inc. *A. Lewis*
RP2383-4	Catalytic Coal Liquefaction With Supercritical Solvents	6 months	30.0	University of Notre Dame *C. Kulik*
RP2390-1	Brine System Analysis	7 months	270.6	Rockwell International Corp. *J. Jackson*
RP2523-1	Estimated Costs and Performance of Small Power Plants With Ambient-Pressure Air-Blown Coal Gasifiers	7 months	208.6	Gilbert Associates, Inc. *B. Louks*
RP2528-3	Small, Low-Cost Movable Gas-Fired Power Plant: Conceptual Design	5 months	54.3	Utah Power & Light Co. *H. Schreiber*
RP2563-3	Synthesis Gas Trace Components	6 months	183.7	Tennessee Valley Authority *W. Weber*
RP2563-4	Cold Flow Attrition Studies: Methanol Catalyst	3 months	48.7	Hydrocarbon Research, Inc. *C. Kulik*
RP2611-1	Dendritic Web Photovoltaic Development	6 months	498.0	Westinghouse Electric Corp. *R. Taylor*
Coal Combustion Systems				
RP718-6	Circulating Fluidized-Bed Design Studies	5 months	180.0	Colorado Ute Electric Association, Inc. *C. Aulisio*
RP983-16	Laboratory Services for CONAC Demonstration	7 months	45.9	Pennsylvania Electric Co. *F. Karlson*
RP1030-26	CCTF Advanced Coal Cleaning Process Modifications	4 months	34.0	Raymond Kaiser Engineers, Inc. *C. Harrison*
RP1179-19	Fabric Filter Testing at the TVA AFBC Pilot Plant	11 months	36.2	Southern Research Institute *W. Howe*
RP1184-6	Integration of Environmental Controls on Coal-Fired Power Plants	7 months	62.0	Bechtel Group, Inc. *F. Wong, E. Cichanowicz*
RP1263-19	PCB-Contaminated Site: Options for Remedial Action	8 months	90.0	Brown & Caldwell *R. Komai*
RP1336-6	Gas Filter Element Evaluation	5 months	60.0	Westinghouse Electric Corp. *O. Tassicker*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1403-9	Technical Assessment of Supercritical Units in the USSR	7 months	70.0	Burns and Roe, Inc. *A. Armor*
RP1403-11	Fireside Corrosion of Superheater/Reheater Alloys for Advanced-Cycle Steam Plants	9 months	64.7	Foster Wheeler Development Corp. *R. Jaffee*
RP1457-2	Effect of Leachate on Clay Liners	13 months	100.0	Battelle, Pacific Northwest Laboratories *R. Komai*
RP1689-14	High-Reliability Condenser Application	27 months	335.1	Heat Exchanger Systems, Inc. *R. Coit*
RP1835-7	Evaluation of New Precipitation Technology	12 months	90.8	Southern Research Institute *R. Altman*
RP1890-4	Failure Cause Analysis: Fireside Corrosion Fatigue of Boiler Waterwall Tubes	11 months	83.0	Battelle, Columbus Laboratories *J. Dimmer*
RP2114-2	Power Plant Water Management (Site 2)	14 months	226.2	CH2M-Hill *W. Micheletti*
RP2533-2	Fabric Filter SO_2 Control by Calcium Sorbent Injection	9 months	150.0	Southern Research Institute *M. McElroy, R. Rhudy*
RP2574-1	Coal Slurry Ash, Iron, and Sulfur Analyzer	11 months	327.9	Science Applications, Inc. *R. Row*
RP2575-3	Emission Reduction Analysis Model: Testing and Validation	5 months	197.6	TERA Corp. *M. Miller*
Electrical Systems				
RP849-7	Load Models for Power Flow and Transient Stability Computer Studies	32 months	474.8	General Electric Co. *J. Mitsche*
RP1143-3	Elimination of Destructive Failures in Distribution Transformers	27 months	621.5	McGraw-Edison Co. *J. Porter*
RP1277-13	Transmission Line Wind-Loading Research	12 months	98.6	Digi-Tek, Inc. *V. Longo*
RP1280-3	Development of a Direct Embedment Foundation Design Procedure	16 months	209.8	GAI Consultants, Inc. *V. Longo*
RP1359-8	Operation and Maintenance of a System for Electromagnetic Interference	37 months	266.0	BDM Corp. *H. Mehta*
RP1499-6	Maintenance and Handling of Perchloroethylene-Filled Electrical Equipment	5 months	38.4	SCS Engineers *G. Addis*
RP1902-3	Mutual Design of HVDC Transmission Lines and Railroads	12 months	208.7	Science Applications, Inc. *J. Dunlap*
RP2015-3	Advanced Polysil Development	5 months	80.4	Battelle, Columbus Laboratories *J. Dunlap*
RP2028-11	Partial and Complete Combustion Products of Transformer Insulation Materials	10 months	130.0	Westinghouse Electric Corp. *G. Addis*
RP2328-1	Confirmation of Generator Standstill Frequency Response Test Methods	33 months	335.1	Consumers Power Co. *J. Edmonds*
RP2330-1	Temporary Operation of Motors With Cut-Out Coils	8 months	103.1	Technology Assessment Group, Inc. *J. White*
RP2367-1	Conductor Deicing: Phase 1	6 months	168.4	Springborn Laboratories, Inc. *R. Tackaberry*
RP2452-1	Advanced Storage Energy Operating Mechanism for Distribution Air Break Switches	35 months	349.2	McGraw-Edison Co. *J. Porter*
RP2473-6	Use of Decomposition Techniques in Expansion Planning	10 months	97.9	Stanford University *M. Pereira*
RP2487-1	Improved Temperature Sensors for Large Generators	6 months	61.0	Westinghouse Electric Corp. *J. Edmonds*
RP2546-1	Conductor Temperature Research	24 months	350.0	Georgia Tech Research Corp. *V. Longo*
RP2551-1	Expanding Polymers for Hydrogenerator Insulation	21 months	176.2	Westinghouse Electric Corp. *B. Bernstein*
RP2591-1	Self-Calibrating Power Angle Instrument	6 months	58.7	Arizona Public Service Co. *D. Sharma*
RP2592-1	Distribution Automation and Load Control System	56 months	7446.9	Westinghouse Electric Corp. *W. Blair*
RP2592-3	Interface Requirements for Distribution Automation and Load Control	12 months	195.4	Energy and Control Consultants *W. Blair*
Energy Analysis and Environment				
RP940-6	NAAQS Exposure Model	20 months	244.6	Pedco Environmental, Inc. *R. Wyzga*
RP1216-10	Exploratory Research of Commercial Hourly Data	11 months	79.9	Synergic Resources Corp. *E. Beardsworth*
RP1491-5	Investigation of the Bubble for Florida Power & Light Co.	9 months	75.0	Tera Advanced Services Corp. *P. Ricci*
RP1988-4	Long-Term Shortage Costs	7 months	64.7	Meta Systems, Inc. *P. Ricci*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2023-6	Free Radical Chemistry in Cloud Water	35 months	406.0	Georgia Tech Research Corp. *D. Lawson*
RP2023-7	Iron and Manganese Catalysis of Sulfur Oxidation: Laboratory Studies	27 months	308.5	The Aerospace Corp. *D. Lawson*
RP2141-8	Global Energy and Carbon Dioxide Scenarios	11 months	48.0	Stanford University *D. Fromholzer*
RP2194-2	Improved Determination of In-Stream Water Requirements	14 months	107.9	Ecological Analysts, Inc. *E. Altouney*
RP2217-1	Industrial End-Use Planning Methodology	24 months	507.0	Battelle, Columbus Laboratories *A. Faruqui*
RP2380-11	Pollutant-Plant-Pest-Pathogen Interactions	17 months	31.9	Cornell University *R. Goldstein*
RP2440-2	Pricing for Alternative Service Conditions	26 months	165.0	Pricing Strategy Associates *H. Chao*
RP2583-1	Indirect Measurement of Atmospheric Hydroxyl	19 months	187.9	SRI International *J. Guertin*
RP2595-1	Decision Frameworks	9 months	445.2	Decision Focus, Inc. *V. Niemeyer*

Energy Management and Utilization

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP128-11	Sodium-Sulfur Battery Supporting Studies	39 months	375.0	SRI International *R. Weaver*
RP1042-19	Carbon Material Supports for Phosphoric Acid Fuel Cells: Preparation and Testing	7 months	118.9	Stonehart Associates, Inc. *J. Appleby*
RP1084-10	Compressed-Air Energy Storage Commercialization Analysis	2 months	39.5	Bechtel Group, Inc. *A. Fickett*
RP1276-23	Cogeneration Technical Support	20 months	68.7	Synergic Resources Corp. *D. Hu*
RP1276-24	Update of the DEUS Computer Program Data Base	7 months	45.4	Black & Veatch Engineers-Architects *D. Hu*
RP1276-99	Cogeneration Symposium	9 months	42.2	Synergic Resources Corp. *D. Hu*
RP1745-17	Design Strategies for Pressure Tunnels and Shafts	24 months	150.0	University of California at Berkeley *B. Mehta*
RP1745-18	Eicher Fish Screen Model Test	12 months	51.8	Eicher Associates, Inc. *C. Sullivan*
RP1940-13	Technical and Planning Assistance for Load Management	7 months	42.0	Electrotek Concepts, Inc. *V. Rabl*
RP1940-14	Field Performance of Residual Local and Distributed Load Controllers	13 months	140.1	BRI Systems, Inc. *G. Gurr*
RP2033-16	Fuel-Fired Supplemental Heat for Heat Pumps	20 months	236.0	Westinghouse Electric Corp. *J. Calm*
RP2036-18	Heat Storage Market Assessment	12 months	103.6	Energy International, Inc. *V. Rabl*
RP2568-2	Nonintrusive Appliance Load Data Acquisition Method	27 months	325.3	Massachusetts Institute of Technology *G. Gurr*
RP2572-2	Superconducting Magnetic Energy Storage: Basic R&D	12 months	223.0	University of Wisconsin at Madison *R. Schainker*
RP2597-3	Technical Information Transfer Assistance	3 months	62.8	Bevilacqua-Knight, Inc. *T. Schneider*
RP2613-3	State-of-the-Art Assessment of Selected Electrotechnologies	7 months	125.0	Battelle, Columbus Laboratories *L. Harry*

Nuclear Power

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP824-3	Evaluation of Techniques for Machinery Vibration Monitoring	26 months	308.2	Radian Corp. *G. Shugars*
RP964-10	Seismic Analysis of Multiple-Support Piping System	7 months	83.2	Westinghouse Electric Corp. *Y. Tang*
RP1163-13	Modular Modeling System Code Enhancement	10 months	83.0	Babcock & Wilcox Co. *M. Divakaruni*
RP1444-5	Validation of Soil-Structure-Interaction Models With Japanese In-Plant Test Data	6 months	82.8	Bechtel Power Corp. *Y. Tang*
RP1581-12	Development and Testing of Fuel Resistant to Pellet-Cladding Interaction	54 months	130.0	British Nuclear Fuels *J. Santucci*
RP1585-10	Small-Plant Modularization Study	4 months	140.3	Westinghouse Electric Corp. *K. Stahlkopf*
RP1845-9	Carryover and Fallback in Steam Generators: Steam Line Break Simulation Experiments and Analysis	33 months	63.0	Massachusetts Institute of Technology *S. Kalra*
RP1930-11	IGSCC Surveillance Instrumentation for Dresden-2 Hydrogen Water Chemistry Program	5 months	71.1	Amdata Systems, Inc. *R. Jones*
RP1931-5	Corium-Concrete Interactions in Stratified Geometry	14 months	50.0	University of Wisconsin at Madison *B. Sehgal*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2079-6	High-Temperature Gas-Cooled Reactor: Seismic Isolation Study	6 months	69.6	Burns and Roe, Inc. *D. Gibbs*
RP2126-4	Advanced PWR Steam Generator/Feedwater Digital Control System	46 months	675.1	Westinghouse Electric Corp. *M. Divakaruni*
RP2126-5	Advanced PWR Steam Generator/Feedwater Digital Control System	31 months	36.7	Tennessee Valley Authority *M. Divakaruni*
RP2160-8	Sludge Behavior in a Steam Generator	18 months	85.6	SC&A, Inc. *Y. Solomon*
RP2183-5	Reactor Coolant Pump Seal Leakage Monitor: Feasibility Study	7 months	47.9	Babcock & Wilcox Co. *G. Shugars*
RP2232-4	Robot Applications for Nuclear Power Plants	2 months	162.2	Odetics, Inc. *F. Gelhaus*
RP2347-16	Computer Integration Tasks of EPRI–DOE Display-Procedure Project (Safety and Analysis)	7 months	80.5	Nuclear Software Services *D. Cain*
RP2356-19	Evaluation of Eastern U.S. Seismic Source Zones	15 months	239.3	Weston Geophysical Corp. *C. Stepp*
RP2356-20	Evaluation of Eastern U.S. Seismic Source Zones	15 months	202.0	Dames & Moore *J. King*
RP2409-2	Instrument Module and Power Supply Drift Reduction	12 months	201.5	Science Applications, Inc. *G. Shugars*
RP2412-2	Advanced Radwaste Assay Methods	31 months	462.5	Science Applications, Inc. *M. Naughton*
RP2430-22	Computer and Software Support for CoMO Project Management System	12 months	188.5	Sun Information Services Co. *D. Gibbs*
RP2455-1	Effects of Steel-Making Practice on Material Property Variability of A533 Grade B, Class 1	12 months	61.4	Lukens Steel Co. *R. Nickell*
RP2455-3	Double Tool Drive System Field Operation: Design and Development of Priority Features	6 months	45.0	Product & Systems Engineering *R. Nickell*
RP2508-1	Use of Plant Information Management Systems for On-Line System Status Assessment	9 months	131.5	Energy Incorporated *B. Chu*
RP2513-1	Review of Nuclear Plant Piping Constructibility	5 months	98.6	Teledyne Engineering Services *G. Sliter*
RP2515-3	Heat Exchanger Improvements	5 months	39.2	University of Pennsylvania *N. Hirota*
RP2518-1	Steam Turbine Disk Lifetime Prediction Manual	6 months	66.7	Southwest Research Institute *N. Hirota*

R&D Staff

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2382-1	Advanced Materials for Land-Based Gas Turbines	18 months	175.0	National Academy of Sciences *W. Bakker*
RP2426-4	Design of an Improved Cr-Mo-V Steel: Production and Evaluation	27 months	150.3	Bethlehem Steel Corp. *R. Jaffee*
RP2608-1	Assessment of Readiness of Structural Ceramics Technology for Use in Large Gas Turbines	10 months	93.8	SRI International *W. Bakker*

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.

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ADVANCED POWER SYSTEMS

Combustion Turbine Design Guidelines Based on Deposition-Corrosion Considerations: Coal-Derived Liquid Studies
AP-2739 Final Report (RP1345-1), Vol. 2; $19.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: A. Cohn

Development of a Data Base on Biomass Diesel-Electric Generation
AP-3549 Final Report (RP2272-6); $10.00
Contractor: Jet Propulsion Laboratory, California Institute of Technology
EPRI Project Manager: S. Kohan

Capacity Factors and Costs of Electricity for Conventional Coal and Gasification–Combined-Cycle Power Plants
AP-3551 Final Report (RP2029-11); $14.50
Contractor: Zaininger Engineering Co.
EPRI Project Manager: B. Louks

Geothermal Downwell Pump Reliability: State-of-the-Art Assessment
AP-3572 Final Report (RP1195-8); $13.00
Contractor: Radian Corp.
EPRI Project Manager: E. Hughes

COAL COMBUSTION SYSTEMS

Nuclear Assay of Coal: Seminar Proceedings—Principles and Applications of Continuous Coal Analysis
CS-989 Proceedings (RP983), Vol. 13; $34.00
Contractor: Raymond-Kaiser Engineers, Inc.
EPRI Project Manager: O. Tassicker

Dry SO_2-Particulate Removal for Coal-Fired Boilers: 22-MW Demonstration Using Nahcolite, Trona, and Soda Ash
CS-2894 Final Report (RP1682-2), Vol. 2; $13.00
Contractor: KVB, Inc.
EPRI Project Manager: R. Hooper

Fugitive Emissions From Coal-Fired Power Plants
CS-3455 Final Report (RP1402-19); $20.50
Contractor: Bechtel Group, Inc.
EPRI Project Manager: M. Miller

Erosion-Corrosion of Metals and Alloys at High Temperatures
CS-3504 Interim Report (RP979-8); $16.00
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: J. Stringer

Augmented Heat Transfer Rates in Utility Condensers
CS-3527 Final Report (RP1689-11); $10.00
Contractor: RIT Research Corp.
EPRI Project Managers: R. Coit, I. Diaz-Tous

Physical, Chemical, and Biological Analysis and Evaluation of Coal Waste Blocks in Fresh Water
CS-3543 Final Report (RP1341-2); $14.50
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EPRI Project Manager: D. Golden

Recovery of Metal Oxides From Fly Ash
CS-3544 Final Report (RP1404-4); Vol. 1, $11.50; Vol. 2, $22.50; Vol. 3, $17.50
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EPRI Project Manager: D. Golden

Mechanism of Fine-Coal Dewatering by Silicone Additives
CS-3548 Final Report (RP1030-20); $13.00
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EPRI Project Manager: R. Row

Condenser Macrofouling Control Technologies
CS-3550 Topical Report (RP1689-9); $28.00
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EPRI Project Managers: I. Diaz-Tous, R. Coit

Process Instrumentation and Control in SO_2 Scrubbers
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EPRI Project Manager: R. Rhudy

Market Survey of Fly-Ash-Derived Magnetite
CS-3615 Topical Report (RP1850-1); $8.50
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EL-3581 Proceedings (RP2028); $37.00
EPRI Project Managers: G. Addis, R. Komai

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EL-3591 Final Report (RP1419-1), Vol. 1; $23.50
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EPRI Project Manager: H. Songster

Transmission Line Design Optimization: TLOP Manuals
EL-3592-CCM Computer Code Manual (RP2151-1); $47.50
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EPRI Project Manager: A. Faruqui

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EM-3534 Final Report (RP1745-6); Vol. 1, $16.00; Vol. 2, $16.00; Vol. 3, $13.00; Vol. 4, $11.50
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EPRI Project Manager: C. Sullivan

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Contractor: Aptech Engineering Services, Inc.
EPRI Project Manager: T. Marston

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TI-3537-SR Special Report; $10.00
EPRI Project Manager: E. Breese

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