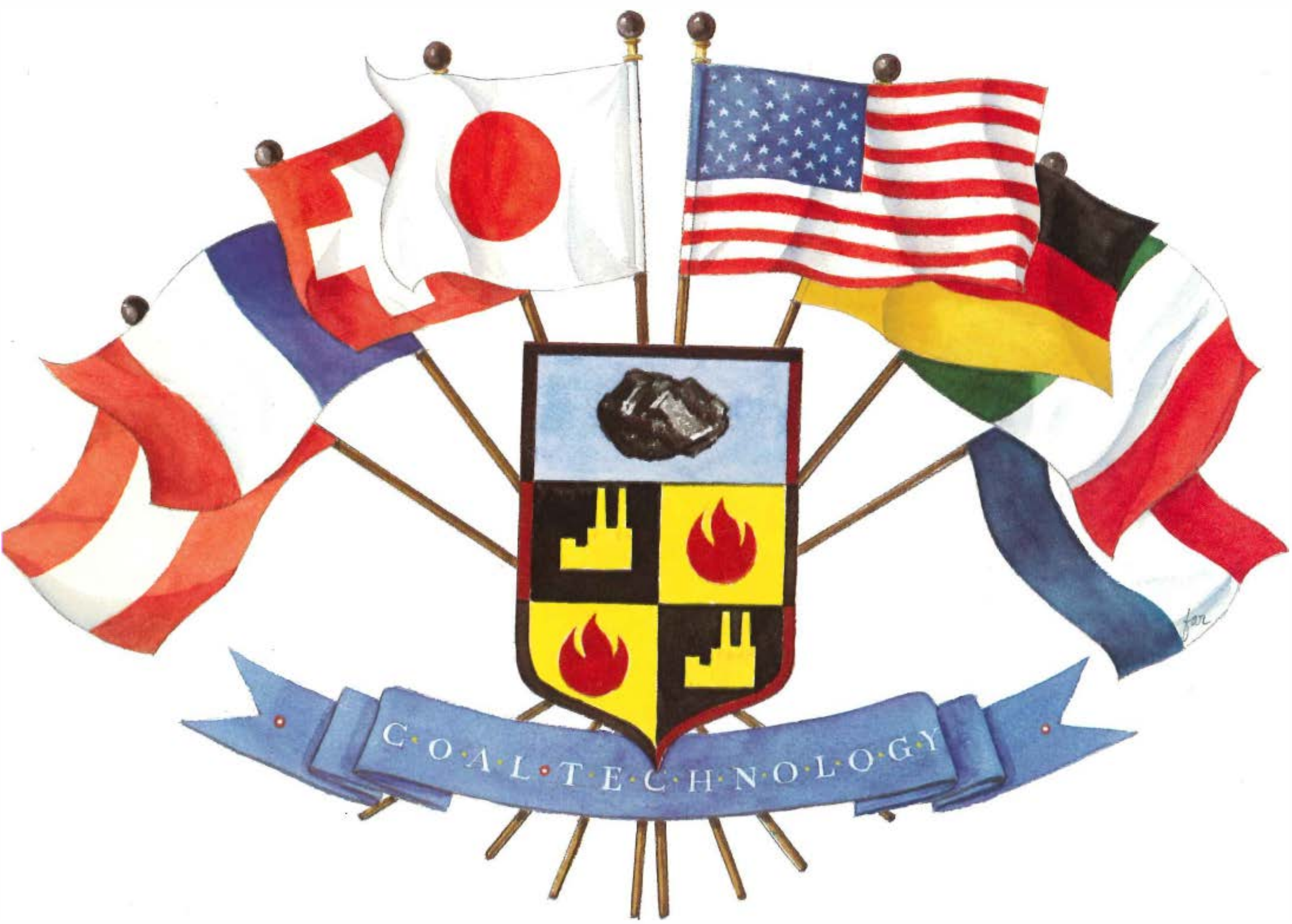
International Integration of Coal Technology

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

JANUARY/FEBRUARY
1986



EPRI JOURNAL is published nine times each year (January/February, March, April/May, June, July/August, September, October, November, and December) by the Electric Power Research Institute.

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.

EPRI JOURNAL Staff and Contributors
Brent Barker, Editor in Chief
David Dietrich, Managing Editor
Ralph Whitaker, Feature Editor
Taylor Moore, Senior Feature Writer
Michael Shepard, Feature Writer
Pauline Burnett, Technical Editor
Mary Ann Garneau-Hoxsie, Production Editor
Jim Norris, Illustrator
Jean Smith, Program Secretary
Christine Lawrence (Washington)
Kathy Kaufman (Technology Transfer)

Richard G. Claeys, Director
Communications

Graphics Consultant: Frank A. Rodriquez

Address correspondence to:
Editor in Chief
EPRI JOURNAL
Electric Power Research Institute
P.O. Box 10412
Palo Alto, California 94303

Cover: Component and materials research to integrate the best features from coal plants around the world promises that the next generation of new and retrofit plants will have higher efficiency and reliability.

EPRI JOURNAL

Volume 11, Number 1 January/February 1986

Advancing Coal Power for the 1990s

An uncertainty that utilities face in generation planning is whether the technology built into today's fossil-fuel-fired generating plants can successfully meet the electricity demands of the 1990s and beyond. Many existing plants will be operated differently as plants designed for baseload duty are switched to cycling service, and some will undergo refurbishment and even design modifications to extend plant lives to 50 years or more. New plants must be part of the planning picture, too, in spite of the many financial and regulatory risks they entail. Even under a scenario of low (2.5% annual) economic growth, as a nation we should be planning for at least 100,000 MW of new capacity on line before the year 2000, virtually all of it generated by fossil fuels.

The efficiency and reliability of fossil fuel power plants evolved steadily upward from the beginning of the century until the early 1960s. Since that time, however, the utility industry has experienced declining plant efficiency and reliability, largely due to a retreat from advanced steam conditions, the use of lower-quality coal, and the retrofitting of environmental controls. The component designs and materials of construction available for building power plants evolved significantly during this period, but such improvements were not always adopted rapidly by utilities because of economic and regulatory deterrents to accepting the risks of being "first into the water" with advancements.

Over the past decade, escalating fuel costs and tightening environmental control requirements have underscored the need for fossil fuel generating plants with better efficiency and optimized environmental controls. The lead article in this issue of the *Journal* is a progress report on a program EPRI began in 1979 to update fossil-fuel-fired technology with improved materials and equipment designs that have been developed over the past 25 years but have not yet been validated in service.

The potential payoff is high. Two EPRI-supported engineering studies completed in 1981 concluded that plant efficiency (heat rate) could be improved 15–20% for new plants and 3% for existing plants without any sacrifice in availability, by applying evolutionary advances in materials and design. In 1984 we implemented a comprehensive development plan for the research needed to achieve these targets. Through EPRI the utility industry will direct $15 million to this effort during 1986–1990, with an additional $10 million in cost sharing from the international team of manufacturers and engineers that we have brought together from the United States, Europe, and Japan.

A companion article in this issue summarizes the results from a parallel program EPRI initiated in 1978 to integrate environmental controls into the generation planning and power plant design process. In this approach, total plant flow requirements for air, liquid, solid waste, and other environmental control interfaces are considered at the outset of design from a systems perspective. In our integrated environmental control program we have identified ways to reduce the capital and operating costs of environmental control by as much as 25%. Several of the improvements have already been demonstrated at pilot scale and applied in utility service.

Success in our advanced fossil fuel plant and environmental control programs will provide utilities and their suppliers with the technology to meet the capacity demands of the 1990s through more fuel-efficient and reliable designs, as well as to operate existing capacity more effectively. Because the thrust of EPRI's advanced plant program is to test, validate, and demonstrate already developed materials and component improvements, the results will be available over the next two to five years. The improvements we have targeted should save $3 million in annual fuel cost at the typical existing coal-fired plant and over $100 million in the cost of electricity over the life of a new 700-MW power plant.

George Preston, Director
Fossil Fuel Power Plants Department
Coal Combustion Systems Division

Authors and Articles

Seven years of research in coal-fired power generation is yielding possibilities for a surprising number of performance improvements. Better still, many of them should be useful in retrofitting baseload plants for cycling and low-load operation with a wider range of fuels than originally intended. **Tapping Global Expertise in Coal Technology** (page 6) surveys an EPRI-sponsored effort that is drawing on design and manufacturing expertise both here and abroad. Michael Shepard, *Journal* feature writer, developed the article with help primarily from three EPRI staff members.

Anthony Armor guided research projects dealing with fossil fuel plant availability and performance after joining the Coal Combustion Systems Division in 1979, and in January 1985 he became manager of the newly established Performance and Advanced Technology Program. Armor was formerly with General Electric Co. for 11 years, working successively in steam turbine engineering and superconducting generator design and development. Earlier, he taught engineering and mathematics for five years at polytechnic colleges in London. Armor holds a BS in mathematics and an MS in mining engineering from the University of Nottingham (England).

George Touchton, a project manager in Armor's program, came to EPRI in January 1985 after 12 years with the gas turbine division of General Electric Co. His work there included responsibility (through startup) for the turbines of the gasification–combined-cycle demonstration plant at Cool Water, California. Touchton has a BS in engineering science from Florida State University and an MS in physics from the University of Illinois.

Robert Jaffee, now a senior technical adviser to EPRI's Materials Support unit, was its manager until 1982. He joined EPRI in 1975 after 32 years with Battelle, Columbus Laboratories, where he became chief materials scientist. A chemical engineering graduate of Illinois Institute of Technology, Jaffee also holds an MS in metallurgy from Harvard University and a PhD in chemical engineering from the University of Maryland.

■

In the short span of about 20 years, emission control systems on power plants have proliferated like the appliances and tangled cords that eventually overload the circuit in an older kitchen. Remodeling efforts are now under way in the form of integrated environmental controls that work together. **Integrating Environmental Control for Coal Plant Efficiency** (page 16), by the *Journal*'s Michael Shepard, is an update on control measures that should see use either singly or in combination, according to EPRI research managers Edward Cichanowicz and John Maulbetsch.

Cichanowicz, who has been with the Coal Combustion Systems Division since 1978, is responsible for research on integrated environmental control systems for the Air Quality Control Program. He formerly specialized in emission measurement and NO_x control. Before coming to EPRI, Cichanowicz spent three years with Energy and Environment Research Corp., where he was involved in the development of low-NO_x burners. He has BS and MS degrees in mechanical engineering from Clarkson College of Technology (New York) and the University of California at Berkeley.

John Maulbetsch has managed the Air Quality Control Program since October 1984. He came to EPRI in 1975 and headed the Heat, Waste, and Water Management Program for eight years. Maulbetsch was previously with Dynatech Corp. for seven years, directing contract R&D on energy topics. He has three degrees in mechanical engineering from the Massachusetts Institute of Technology, where he taught for three years.

■

New hardware is making pumped hydroelectric energy storage possible at higher heads. And in several instances, pumped hydro is producing greater cost savings than expected. Together, technology and economics may create new opportunities for this essentially mature energy alternative. Taylor

Moore, the *Journal's* senior feature writer, traces these developments in **Pumped Hydro: Backbone of Utility Storage** (page 24). Two staff members of EPRI's Energy Management and Utilization Division provided technical background.

James Birk became director of the Advanced Conversion and Storage Department in October 1985 after five years as manager of the Energy Storage and Hydroelectric Generation Program. He joined EPRI in 1973 as a project manager for battery energy storage R&D. Earlier, Birk was a senior scientist with Rockwell International Corp. for six years. He has BS and PhD degrees in chemistry from Iowa State University and Purdue University.

Robert Schainker, an EPRI staff member since 1978, succeeded Birk as manager of the Energy Storage Program last October. He became a research manager in the program in 1980, following work on combustion turbine projects for the Advanced Power Systems Division. Schainker was formerly with Systems Control, Inc., for nine years, holding engineering and managerial responsibilities in energy and environmental studies. He has a BS in engineering science, an MS in systems engineering, and a PhD in applied mathematics, all from Washington University (St. Louis).


Schainker


Armor


Jaffee


Maulbetsch

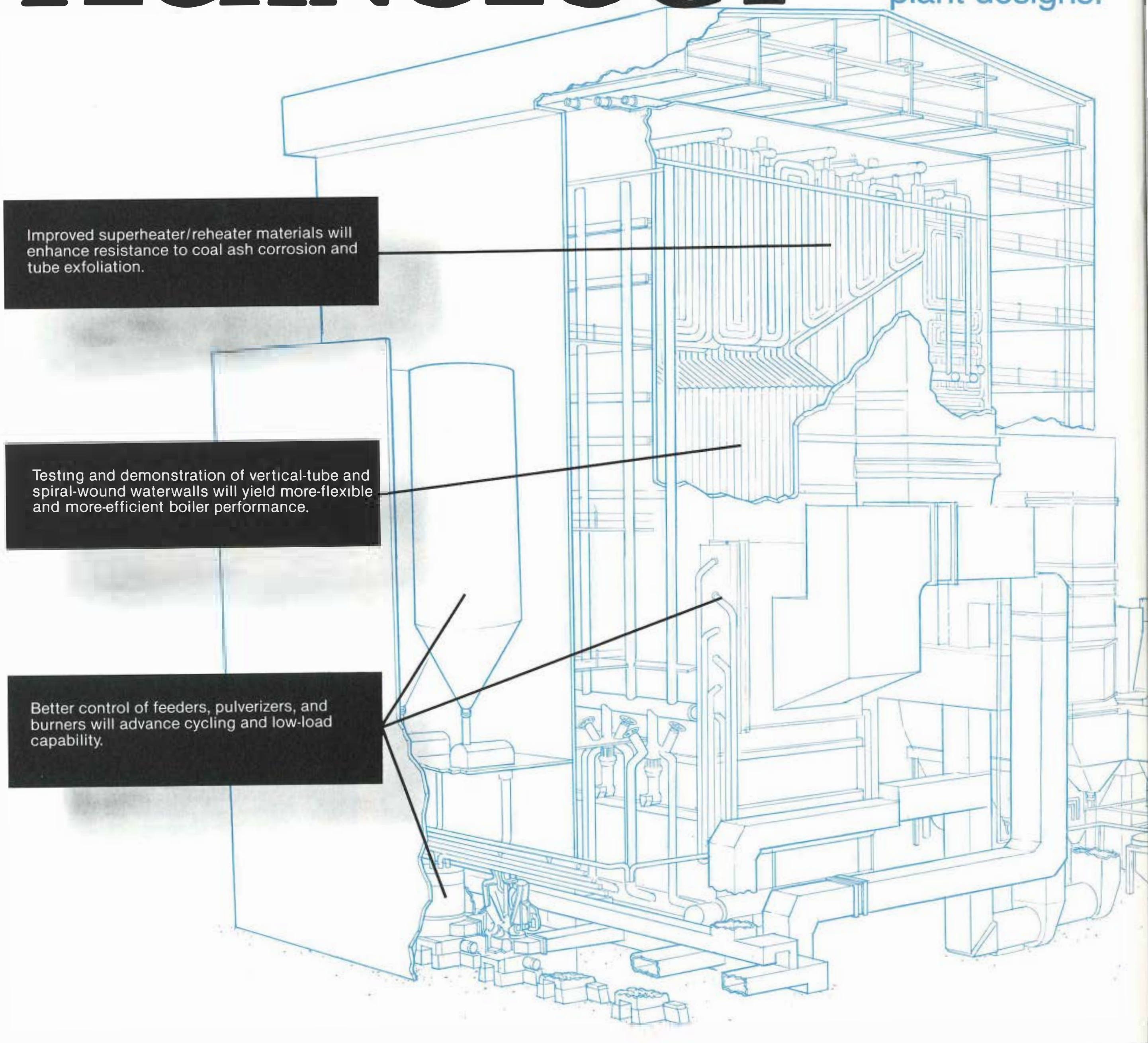

Birk

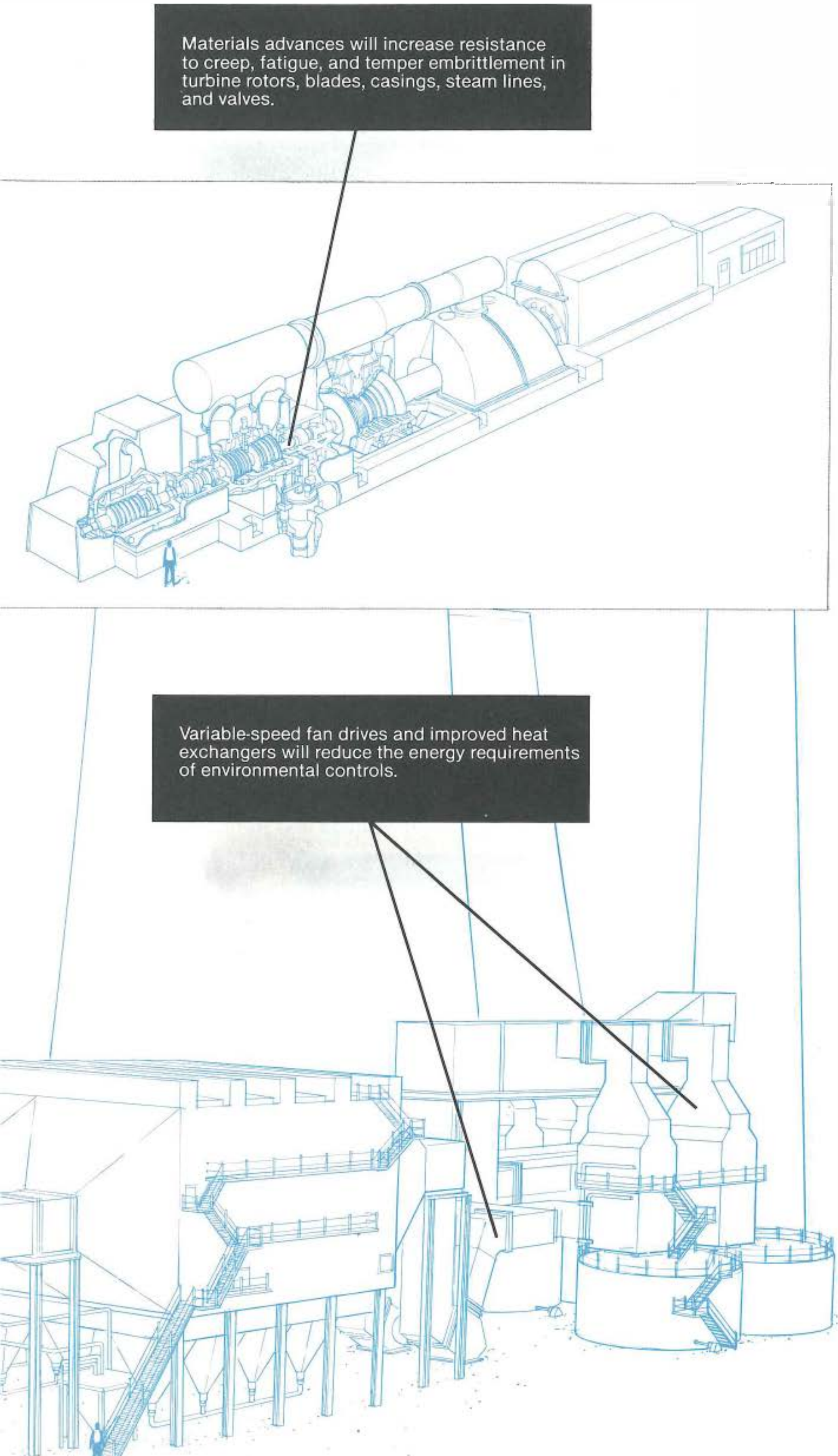

Touchton


Cichanowicz

TAPPING GLOBAL EXPERTISE IN COAL TECHNOLOGY

A consortium has been formed to draw together the best in fossil fuel plant technology from around the world. The intention is to speed the creation and development of improved components and materials leading to advanced power plant designs.





As if frozen in time, America's coal-fired power plants continue to be built principally with materials and designs developed 30 years ago. Of course there have been some changes in three decades. The average size of stations grew throughout the 1960s and 1970s. There was a 10-year flowering of high-efficiency supercritical plants, followed by a retrenchment to lower-temperature and lower-pressure designs. A new generation of environmental controls emerged. But the basic technology of fossil-fuel-fired electricity generation has stayed virtually the same since the days when the 1950s Chevrolets were rolling off the assembly line.

After steady improvement, beginning at the turn of the century, the average thermal efficiency of our coal-fired generation capacity peaked in 1963 and has declined since, as have availability and reliability. Throughout the 1960s economies of scale from large plants and inexpensive fuels offset this declining performance and sustained the traditional decline in electricity prices. With costs falling and power demand booming, utilities had little incentive to explore new R&D needed to improve coal-fired plant performance. The old designs were providing sufficient power at reasonable cost.

The picture changed dramatically in the 1970s. High interest rates, inflation, declining construction productivity and coal quality, escalating fuel costs, and the growing complexity and cost of environmental controls combined to increase the real cost of electricity by 60% from 1970 to 1983. Oil price and supply disruptions and the virtual moratorium on construction of new nuclear power plants made it clear that coal (which provides almost 60% of our electricity today) would provide an even greater share of our power for some time to come. But conventional coal-fired technology was outmoded. The fleet needed a tuneup and new designs and materials to get it rolling forward again—toward the challenges of the 1980s and beyond.

Charting a course

By the late 1970s EPRI and the utility industry were developing new fossil fuel power generation technologies: improved pulverized-coal-fired plants, fluidized-bed combustion, and gasification–combined-cycle systems, all aimed at combining more-effective environmental control with higher productivity. Kurt Yeager, EPRI's vice president for Coal Combustion Systems, observes, "Our goal is to improve the full scope of fossil fuel power technology so that its potential can be realized regardless of the combustion cycle a utility chooses."

In 1978 EPRI commissioned two studies on the prospects for improving fossil-fuel-fired power plant technology. The study teams, one headed by General Electric Co. and Babcock & Wilcox, Inc., and the other by Westinghouse Electric Corp. and Combustion Engineering, Inc., both concluded that readily achievable, evolutionary materials and design advances would allow the industry to improve the heat rate of new plants by 15–20% and that of existing plants by 3%, with no loss of availability. About 40% of the projected efficiency improvements would come from an increase in steam temperatures and pressures. The remaining 60% would arise from improved equipment efficiency and greater use of waste heat.

The Westinghouse study concluded that such improvements could be achieved with a 4% reduction in electricity costs. Over the life of a new 700-MW plant such savings would easily exceed $100 million. Moreover, the 15–20% reduction in heat rate would reduce production of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates by the same amount, leading to significant capital and operating cost savings in environmental controls. (These savings are discussed extensively in the article on integrated environmental control in this issue.)

These promising findings prompted EPRI to conduct a global survey of progress in improved fossil fuel power plant technology and to produce an R&D development plan for achieving the performance improvements that the General Electric and Westinghouse studies had identified. "Along with our contractor, Gilbert/Commonwealth, Inc., we reviewed advanced technology with every major boiler and turbine manufacturer and every major utility in the United States, Japan, and Europe," explains Anthony Armor, manager of EPRI's Performance and Advanced Technology Program. "This groundwork put us in touch with state-of-the-art developments in all aspects of coal combustion and steam path design, and it helped us to clearly define what utilities need in the future from their fossil-fuel-fired plants."

This survey of industry priorities revealed significant changes from the days when large, coal-fired baseload plants were the favored choice of utility planners. In addition to the need for more-efficient and -reliable plants, flexibility is now a key concern. With nuclear plants providing much of the baseload power in many regions, utilities require their existing coal stations and new plant designs to cycle with the peaks and valleys of demand and to operate smoothly at loads as low as 15% of capacity. The industry is rethinking the optimal size for new capacity additions, wants the option of building smaller plants, and requires shorter construction times. Fuel flexibility is also important; utilities want plants that can burn a wider range of coals. Improvements to existing plants are a clear priority, with over 1200 fossil fuel units larger than 100 MW currently in operation and new capacity expensive and difficult to bring on-line.

An international journey

Recognizing that many of the utilities' needs for advanced components for conventional coal-fired plants cannot be satisfied by the equipment suppliers alone (who reduced their R&D efforts in response to the slack market they faced for the past decade), EPRI has stepped up its involvement. With the goal of developing the best technology possible for U.S. utilities, the Institute has signed contracts with power equipment manufacturers from Europe, Japan, and the United States. These firms will work cooperatively under EPRI's leadership to demonstrate improved materials, designs, and procedures in existing commercial plants and large-scale laboratory facilities. Focusing on boilers, turbines, balance-of-plant components, and retrofit applications, the manufacturers will validate individual components in separate installations and develop equipment specifications that can be used with confidence by utilities.

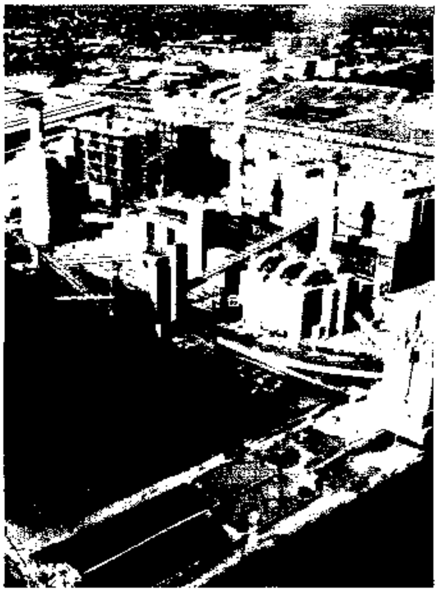
George Preston, director of EPRI's Fossil Fuel Power Plants Department, explains, "At this stage of our program, testing in separate locations is the most attractive way to demonstrate that these improvements can work in a variety of settings and in retrofits, as well as in new installations. As a follow-up, we plan a full-scale demonstration at one of the new plants of the 1990s."

"When this work is complete," says Armor, "utilities will be able to specify such advanced equipment and materials as variable-pressure supercritical boilers, heat pipes for flue gas heat exchange, creep-resistant 12-chrome turbine rotors, and low-excess-air burners, secure in the knowledge that they have been fully validated in utility service and that their reliability will be as good as any technology now operating."

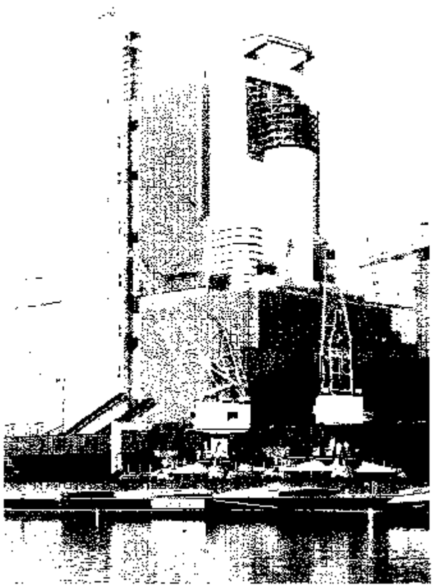
The turbine research is led by a consortium of General Electric (United States) and Toshiba (Japan) and includes Alsthom (France) and M.A.N. (Federal Republic of Germany). There

Model Plants

EPRI's research is gleaning the best technology from American, Japanese, and European plants. Some of the desirable features being developed are contained in the plants shown here. Philadelphia Electric Co.'s Eddystone plant was commissioned in 1959 with higher steam conditions than any plant to this day (5000 psi, 1200/1050/1050°F). Eddystone was recently life-extended to the year 2005. The Matsushima station of the Electric Power Development Corp. is representative of Japan's most modern, high-efficiency coal-fired plants with steam conditions of 3500 psi (24 MPa), 1000/1000°F (538/538°C). The 700-MW Heilbronn plant in the Federal Republic of Germany is characteristic of European designs with its spiral-wound boiler and capacity for quick startup, shutdown, and duty cycling.


Eddystone

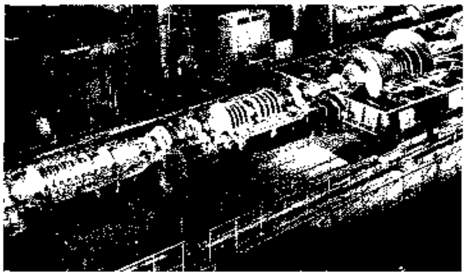

Matsushima

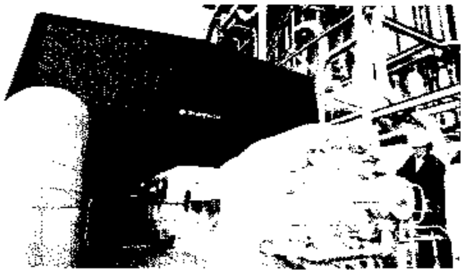

Heilbronn

Focus on Components

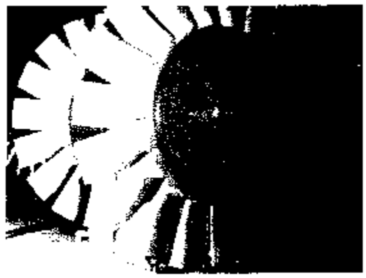
The improved coal-fired plant research focuses principally on the development and validation of advanced materials and designs for major plant components. Metal alloys that maintain their strength at high temperature and can withstand the frequent temperature changes that result from cycling will be used for turbine rotors and casings and for steam pipe headers. To mitigate creep and fatigue encountered in conventionally cast rotors, researchers will forge demonstration rotors from improved materials. Thin layers of special steel alloys will be used on the surfaces of reheaters and superheaters to withstand coal ash corrosion, which is particularly acute at high temperatures. Innovative pump seal designs are being developed to improve the performance of boiler feed pumps operating under high pressure. Variable-speed drives are one option being pursued for reducing the power demand of large fans.

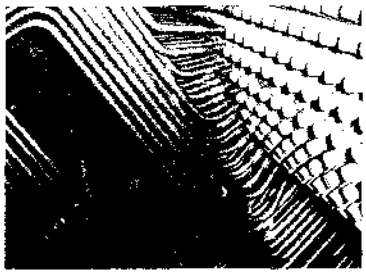

Welded turbine rotor


700-MW steam turbine


Boiler feedwater pump


Reheater


Axial-flow fan


Header-type feedwater heater

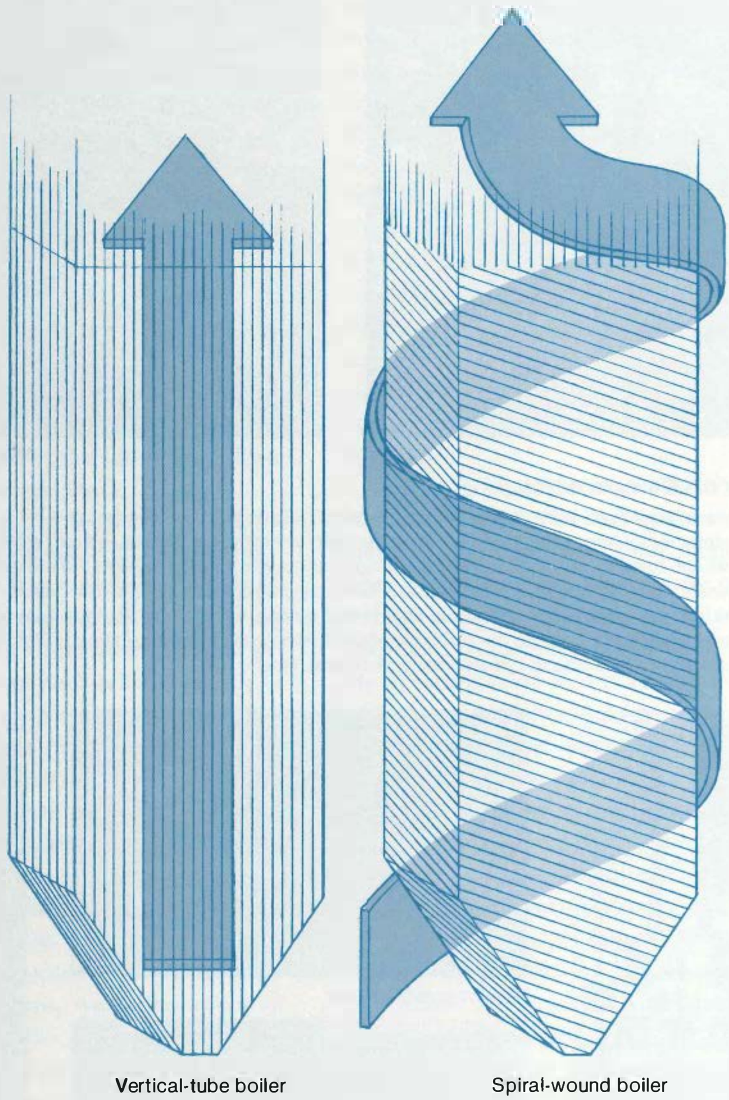
are two groups focusing on boiler technology. Combustion Engineering (United States) is the major contractor in an effort with Mitsubishi Heavy Industries (Japan) and Sulzer Bros. (Switzerland), while Foster Wheeler Development Corp. (United States) is collaborating with Ishikawajimi-Harima Heavy Industries (Japan) in a smaller effort. High-pressure feedwater pumps are being developed by two Swiss firms, Sulzer Bros. and Brown Boveri. Brown Boveri will also work on high-pressure feedwater heaters. For state-of-the-art control and safety systems, EPRI turned to Gilbert/Commonwealth and Babcock & Wilcox's subsidiaries, Bailey Controls, Inc. (United States) and Bailey of Japan, Inc. In addressing performance improvements for currently operating plants, EPRI has selected more than 10 companies to develop and validate retrofit applications aimed at improving the heat rate and availability of existing plants.

"We are particularly heartened by the high degree of cost sharing in this project," reports EPRI Project Manager George Touchton. "More than 30% of the boiler and turbine development expense is being borne by the contractors, with slightly smaller percentages in the balance-of-plant and retrofit areas. This demonstrates the real commitment that the equipment suppliers are making in this new technology."

Armor states that "there is good reason for drawing these international manufacturers into research aimed at the needs of American utilities." He explains that the Japanese and European utility industries evolved under unique conditions, which gave rise to technologies somewhat different from those developed in the United States. The principal differences are those in boiler and turbine designs aimed at greater cycling and control capability, areas that are of growing interest to American utilities. Because of their extensive design and operating experience with these innovative ideas, Armor believes

Comparing Boiler Designs

EPRI is assessing vertical-tube boilers (typical in the United States) and spiral-wound boilers (common in Japan and Europe) in side-by-side comparisons of their performance in supercritical, sliding-pressure operation. In spiral-wound designs, steam passes through helical bundles of metal tubes that surround the furnace. In vertical-tube designs, the four furnace walls are formed by vertical pipes, providing some construction advantages over the spiral tubes, which require fairly elaborate support structures. However, spiral-wound designs permit more-accurate control of steam temperature to the turbine, an important feature for units that will be cycled regularly. Because each tube passes through all the temperature zones of the boiler, steam temperatures are the same at the exit of all the spiral-wound tubes.



the international firms will be valuable partners in advancing fossil-fuel-fired technology for our domestic utilities.

After World War II the Europeans developed separate, national power networks with minimal interconnection across their borders. Because they could not wheel power great distances to smooth out local demand fluctuations, European utilities needed plants that could cycle on and off the line quickly and efficiently. The popularity of district heating (the use of one plant to produce steam for space and process heating as well as electricity) reinforced this need, because plants had to be able to run at low load when electricity demand was depressed but heat from the plants was needed. Consequently, European manufacturers built spiral-wound boilers for sliding-pressure operation, turbine steam bypass systems, lightweight turbine casings, and welded turbine rotors. The plants that resulted were well suited to quick startup and shutdown and to load cycling.

The Japanese power industry was shaped by different forces. Because of the scarcity of domestic energy resources, the Japanese are particularly vulnerable to supply disruptions and high fuel prices. To minimize their fuel demand they have aggressively developed nuclear capacity and high-efficiency, supercritical fossil-fuel-fired plants to meet their electricity demand. Japan is aggressively pursuing R&D in supercritical designs and appears now to be the world's leader in this technology. This view is underscored by the fact that two 700-MW supercritical, sliding-pressure coal-fired boilers are under construction at the Matsuura station of Kyushu Electric Power Co., and a 700-MW, 4500 psi (31 MPa), 1050/1050/1050°F (566/566/566°C) plant is being built at Chubu Electric Power Co.'s Kawagoe station. (These figures refer to the steam's pressure as it enters the high-pressure turbine, and the steam's temperature as it enters the high-pressure turbine and the two reheat turbines.

EPRI and its contractors will devote roughly $25 million over the next five years to the development of the improved coal-fired plant. Initially the work will focus on validating the performance of advanced materials and designs that currently exist but are rarely applied. The improved materials are expected to overcome such problems as high-temperature corrosion of boiler tubes, creep fatigue of turbines, fatigue of feedwater pumps and heaters, erosion of large valves, and low-temperature corrosion of flue gas desulfurization equipment. The near-term goal is to provide utilities with the option of buying from American manufacturers a reliable, high-efficiency plant with cycling capability and steam conditions up to 4500 psi, 1050/1050/1050°F in sizes from 200 to 1000 MW. Such an advanced design, fueled by liquefied natural gas, is already under construction in Japan.

Armor stresses that many of the advances being developed can be applied selectively. Some utilities may want to add cycling or low-load capability. Others may choose to elevate steam temperature without raising pressure. Because the various advances will be developed and validated separately, utilities will have flexibility in choosing which ones to adopt.

By 1989 the researchers hope to develop reliable designs for even higher steam conditions. Incorporating materials that are not yet commercialized but have a high probability of being cost-effective, they expect to make the technology available for a 4500 psi (31 MPa), 1100/1100/1100°F (593/593/593°C) plant with a heat rate of 8500 Btu/kWh (including the power demand of environmental controls), 10% better than the best 3500 psi (24 MPa), 1000/1025/1050°F (538/552/566°C) supercriticals now in operation and 20% better than conventional 2400 psi (17 MPa), 1000/1000°F (538/538°C) single-reheat designs. The thrust of this effort will be to incorporate existing advanced materials to improve higher-temperature operation of superheaters, reheaters, and turbine forgings and casings.

Coupling the heat rate improvements (which will reduce fuel demand and emissions per unit of capacity) with state-of-the-art environmental controls, the improved coal-fired plant will be cleaner and more efficient than most fossil fuel plants now operating. "An advisory committee comprised of industry experts and EPRI staff is working to ensure that the latest developments in environmental control technology are incorporated into the improved fossil-fuel-fired power plant R&D as it evolves," explains Touchton.

Focus on materials

Although environmental performance is an important component of this work, the primary focus of the improved fossil-fuel-fired power plant effort is boiler and turbine design modifications and improved materials. Materials issues, in fact, have played a pivotal role in shaping the development plan. "The designs and steam conditions in the development plan were selected to accommodate what we knew or thought we could expect from the materials," explains EPRI's Robert Jaffee, senior technical adviser in the Materials Support unit. "To a large extent, the improvements we are seeking will come from applying existing advanced materials to solve problems that have hampered the performance of coal-fired plants—particularly supercritical units—for many years." Liquid ash corrosion, for example, commonly plagues superheaters and reheaters in both subcritical and supercritical plants burning high-sulfur coal that contains alkali chloride impurities. To produce the 1100°F (593°C) steam required in the advanced plant, the metal walls of superheaters and reheaters must reach 1200–1300°F (649–704°C), a range in which, for conventional materials, mol-

COAL-FIRED PLANTS: TECHNOLOGY IN TRANSITION

For the first half of the century, utilities and equipment manufacturers pushed power generation technology to ever higher levels of performance. Steam temperatures and pressures, in particular, were increased in pursuit of higher thermodynamic efficiency. The first coal-fired central station plant, built by the Hartford Electric Light Co. in 1902, had a capacity of 2 MW. Steam entered its turbine with a pressure of 180 psi (1.2 MPa) and a temperature of 380°F (193°C). The plant's thermal efficiency was about 10%, with a heat rate of roughly 35,000 Btu/kWh. The early 1920s witnessed the advent of pulverized-coal furnaces, and by the end of that decade some utility boilers were producing 1200 psi (8 MPa), 600°F (316°C) steam. Materials durability became a problem as steam temperatures exceeded 800°F (437°C). The development of carbon-molybdenum steels and other alloys solved creep and fatigue problems and allowed steam conditions to continue climbing. By the early 1950s steam conditions of 2400 psi (17 MPa), 1000°F (538°C) were commonplace, yielding thermal efficiencies of up to 34% and heat rates near 10,000 Btu/kWh.

In 1957 the Ohio Power Co. broke through to a new era in steam conditions with America's first supercritical plant, the 125-MW, 4500-psi (31-MPa), 1150°F (621°C) Philo No. 6 unit. At supercritical conditions (above 3206 psi; 22 MPa), water and steam become indistinguishable and adding heat raises the fluid's temperature directly, thus leading to a corresponding increase in potential thermodynamic efficiency. The pinnacle of steam conditions was reached in 1959, with the commissioning of Philadelphia Electric Co.'s Eddystone No. 2 (5000 psi, 34 MPa; 1200/1050/1050°F, 649/566/566°C). No plant before or since has operated at such extreme conditions.

Through the 1960s and 1970s more than 150 supercritical units with a combined capacity of over 80,000 MW were built in the United States. Other countries followed suit. Today, more than 60 supercritical plants are operating in Japan and more than 250 are operating in the Soviet Union. Because of concerns about materials durability, most designs retreated from the operating levels of Eddystone to more-moderate supercritical steam conditions of 3300–3800 psi (23–26 MPa), 1000°F (538°C).

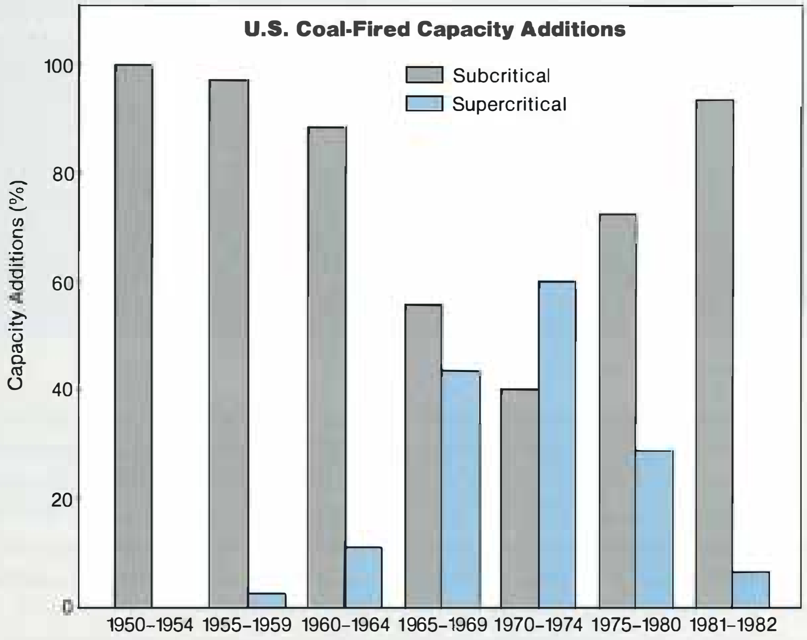
Other changes unrelated to steam conditions were occurring at the same time. Many of the early supercritical plants were considerably larger (by hundreds of megawatts) than earlier generations of coal-fired plants. Some featured pressurized boilers, a dramatic departure from the industry norm of burning fuel at atmospheric pressure. A new generation of environmental control systems added further complexity to the new stations.

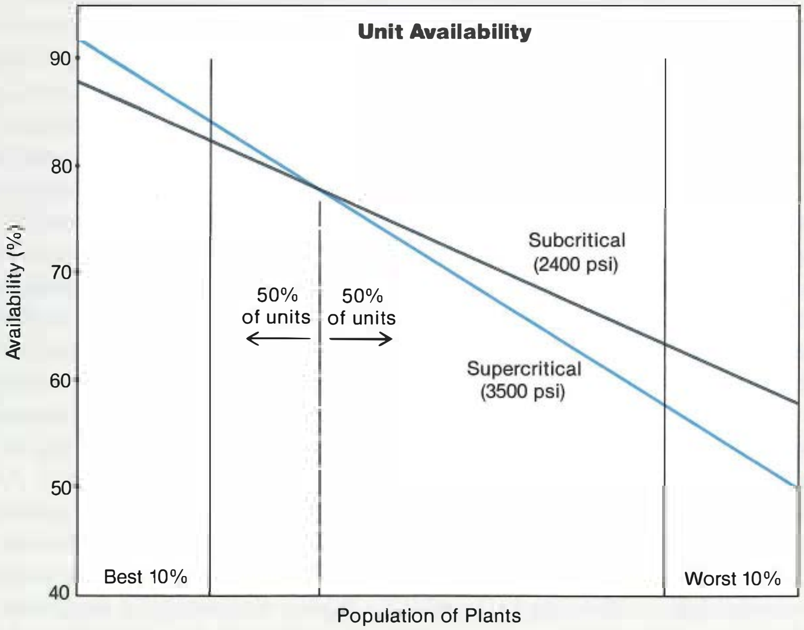
As often happens when many parts of a complex system are changed at the same time, some of the early supercriticals performed poorly. Control of the supercritical boilers, particularly during startup and shutdown, was (and still is for some units) a complex procedure requiring increased operator attention. The pressurized furnaces—unrelated to steam pressure—proved to be particularly troublesome, sending ash through leaks in expansion joints, door seals, fan connections, and observation ports into plant control rooms. Utilities operating later-generation plants returned to atmospheric pressure boilers. Problems with the early plants, although they had little to do with steam conditions per se, gave the first-generation supercritical plants a reputation for being unreliable and difficult to operate. Largely for these reasons, the American utility industry retreated in the late 1970s to the subcritical designs (2400 psi, 17 MPa; 1000°F, 538°C) of the 1950s.

Recent studies have shown that the industry's fears were unfounded; the availability and performance of the later-generation supercriticals (particularly those with atmospheric pressure boilers) can be as good as or better than those of standard subcritical plants. In addition, automated plant controls are relieving operators of the control complexities related to plant startup and load swings. William von KleinSmid, a senior research engineer with Southern California Edison Co., serves on an advisory committee for EPRI's improved fossil-fuel-fired plant research. "When I first got involved," he says, "I had concerns based on the early history of supercritical plants. But after looking at performance data and talking with people who have built and operated supercriticals, I think it's the only way to go for both efficiency and reliability." Many utility observers echo von KleinSmid's comments. Through this program, EPRI is working to ensure that whether utilities pursue subcritical or supercritical coal-fired designs, they have the best technology to work with. □

Summarizing 30 Years of Subcritical and Supercritical Plant Performance

American utilities began installing supercritical (high-pressure) plants in the early 1960s in pursuit of higher efficiencies. By the early 1970s, supercritical plants represented more than half of capacity additions, but interest quickly waned as problems began to develop with some of the earliest supercritical units. Comparison of availability data shows that although these early supercriticals were often less reliable than their contemporary subcriticals, many later-generation supercriticals, with more-mature designs, have surpassed subcriticals in availability.



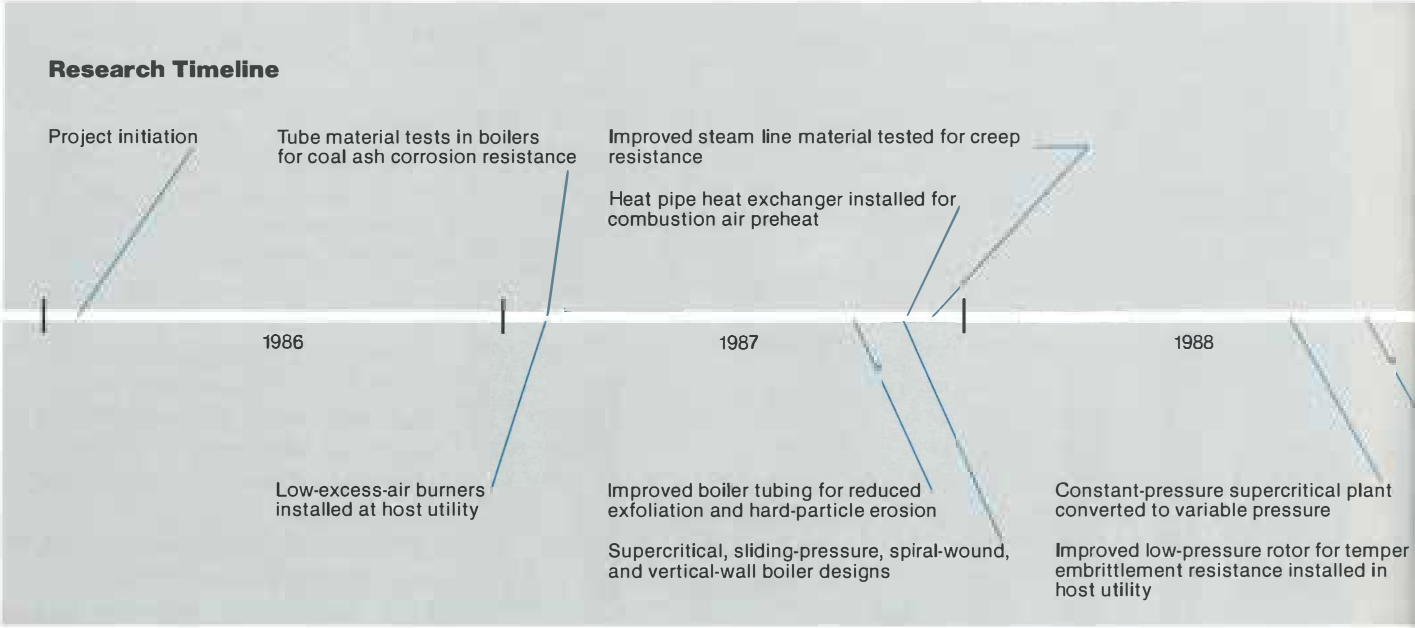


ten ash can be highly corrosive, accelerating tube wastage. These problems will be solved by replacing or coating the metals now used with corrosion-resistant high-chromium alloys.

High-chromium alloys also will be used to reduce oxidation on the steam side of superheaters, reheaters, and piping. Because the rate of steam oxidation grows exponentially with temperature, it is a greater problem in higher-temperature plants. Steam oxidation can lead to the flaking off of internal scale (exfoliation), which can clog narrow steam tubes and blow at high velocity into turbines, causing blade and nozzle erosion.

"One of the greatest challenges in the improved fossil-fuel-fired plant work," says Jaffee, "is to validate the improved materials from which we will build thick-walled and massive components like main steam pipes and turbine rotors." When materials heat and cool, they expand and contract. In materials with poor thermal conductivity, one surface may be much hotter than the opposite surface. This leads to varying amounts of expansion at different points in the material. The resulting thermal stress can crack the metal.

Ferritic steels are generally preferred for such applications because of their high thermal conductivity and low coefficients of expansion. Until recently, however, austenitic steels had to be used for applications over 1100°F (593°C), a threshold at which ferritic steels rapidly lose creep strength. Extensive development has been devoted to strengthening ferritic steels with chromium, molybdenum, and other metals. One alloy, a steel containing 9% chromium and 1% molybdenum, looks very promising for the main steam pipes and heavy-section turbine components because it conducts heat well, expands and contracts minimally, and holds its strength at temperatures above 1100°F. Another high-chromium alloy (12% Cr) holds promise for the large rotors used in intermediate- and high-



pressure turbines. Other materials developments, including embrittlement-resistant low-pressure rotors, are being pursued by the R&D teams.

Design improvements

Materials advances are central to the utilities' evolving needs for efficiency, cycling capability, low-load operability, good environmental performance, and reliability. Optimizing these diverse goals, however, also calls for a broad range of design improvements. Consequently, the improved plant project calls for a number of specific design-related developments. These range from spiral-wound, sliding-pressure, supercritical boilers to new turbine blade configurations; improved seals, pumps, heaters, and valves; better burner designs; new control systems for on-off cycling; and more-effective waste heat recovery and reuse.

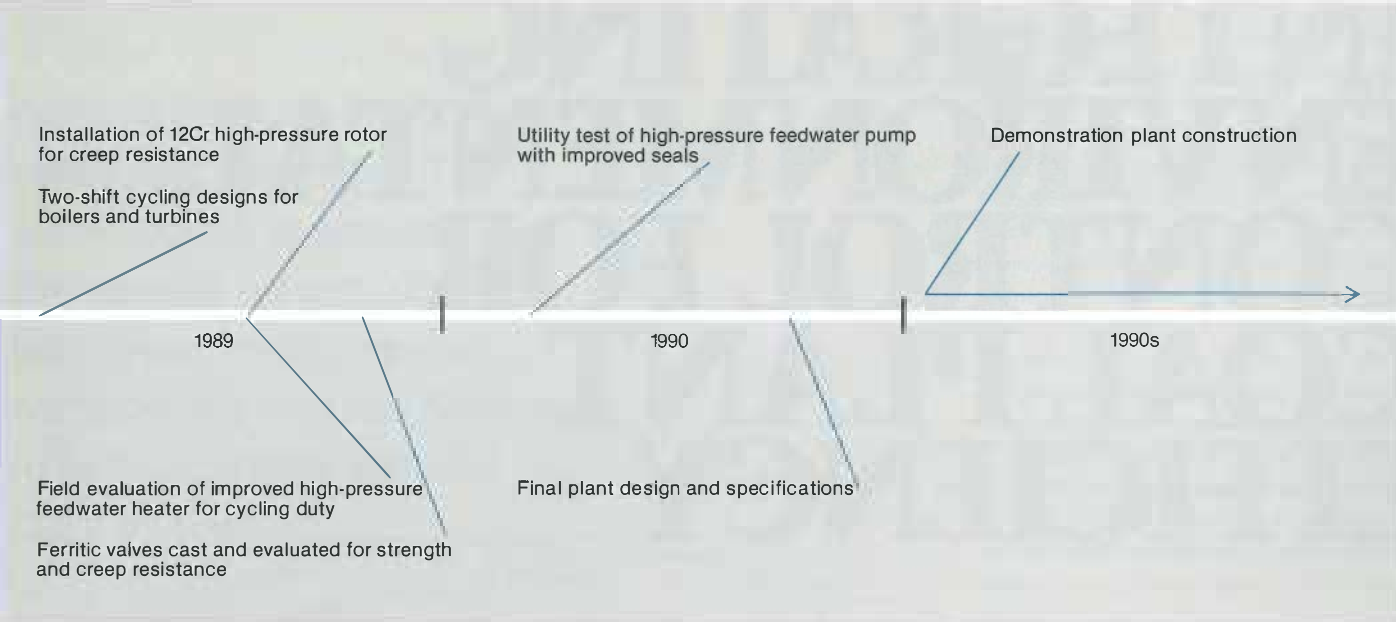
No one of these changes can be considered in isolation, because they interact in important ways—sometimes synergistically and occasionally at cross-purposes. Burner design, for instance, affects heat rate, gaseous emissions, waterwall corrosion, and the ability of the plant to cycle and operate at low load. Burners designed for fuel-rich, low-excess-air combustion minimize the production of undesirable NO_x and sulfur trioxide (SO_3), help keep the flame going at low loads, and improve the plant's thermal efficiency by reducing the amount of air unnecessarily heated and passed through the plant. But the reducing chemical conditions formed inside the boiler by fuel-rich combustion can eat away at waterwall tubes (which last longer in a high-excess-air, oxidizing atmosphere) and can lead to material wastage and, ultimately, to reduced reliability.

An EPRI-funded coal burner test effort at the Potomac Electric Power Co. (Pepco) Morgantown No. 2 unit will try to garner the advantages of low-excess-air combustion while avoiding waterwall wastage. The approach being pursued is to adjust the burners and dampers in a manner that yields small, fuel-rich pockets around the burners surrounded by high-excess-air zones near the waterwalls.

Pepco anticipates a heat rate improvement of over 100 Btu/kWh by reducing excess air in the furnaces from about 25% to around 15% and reducing by 30°F (17°C) the exit temperature of stack gases through improved heat recovery. By reducing the production of SO_3 (which condenses at low temperature to form corrosive acids) low-excess-air burners make it possible to remove more heat from the flue gas while avoiding corrosion of the air heater and stack.

The Morgantown No. 2 unit was selected for this project because it has already been equipped with extensive performance monitoring technology as part of another EPRI-supported study. "With Pepco," says Armor, "we are testing improved instrumentation and methods for accurately monitoring the performance of turbines, boilers, heat exchangers, fans, pumps, and other components. This unique capability also makes the Morgantown plant an excellent place to test new approaches to low-excess-air combustion."

"Low-excess-air operation requires close monitoring," explains Thomas Crim, manager of performance projects for Pepco, "to keep the combustion process fine-tuned and to protect the waterwalls from wastage. With tight



monitoring and control, low-excess-air combustion can provide significant efficiency gains with no sacrifice in reliability."

The heat recovery effort at the Morgantown plant is representative of a class of design improvements that can achieve significant efficiency gains in new plants and in retrofit applications. An estimated 200–300 Btu/kWh reduction in heat rate can be attained by eliminating leaks in heat exchangers, making productive use of heat that is otherwise wasted, and improving the efficiency of fans, pumps, condensers, and turbines. Heat pipe heat exchangers, for instance, will be tested as an alternative to conventional designs that use rotating metal grates to transfer flue gas heat to incoming boiler air. The heat pipe uses a working fluid, such as water or Freon, that evaporates and condenses as it circulates in a sealed, leak-proof loop. This results in more-efficient heat transfer and leak-free operation, a feature not possible with conventional designs. "Up to a dozen of these advancements will be installed and validated at existing utility sites," reports Touchton, "to demonstrate the retrofit potential of the improved power plant project."

The home stretch

Much of the legwork for the improved fossil fuel plant is complete. State-of-the-art practices from around the world have been assessed, the critical areas for development have been identified, and an international team of contractors has been assembled to bring the promise of the improved plant to fruition. After a 30-year period of relative inactivity, fossil-fuel-fired technology is on the move again, rolling toward a horizon rich with opportunity. Within five years the technology will be available to build reliable and flexible 4500 psi (31 MPa), 1100/1100/1100°F (593/593/593°C) designs. Further into the 1990s, steam conditions of 5000 psi (34 MPa), 1200°F (649°C)—the original design conditions of the Eddystone plant—may become common. For this to happen, development and testing of materials and designs will be needed to produce austenitic steel rotor forgings, higher-strength alloys for boiler tubing, and improved pumps and feedwater heaters. A full-scale test facility may be required to meet these goals. If all goes as planned, these improvements will be attained during the next decade, and the technology that ushered in the electric age over 80 years ago will be poised to meet the power generation challenges of the twenty-first century. ■

Further reading

A Study of Coal-Fired Power Plants in Japan. Final report for RP2305-2, prepared by Bechtel Group, Inc., June 1985. EPRI CS-4092.

Development Plan for Advanced Fossil Fuel Power Plants. Final report for RP1403-4, prepared by Gilbert Associates, Inc., May 1985: EPRI CS-4029.

A. F. Armor and R. D. Hottenstine. "Cycling Capability of Supercritical Turbines: A Worldwide Assessment." ASME/IEEE Joint Power Generation Conference, Milwaukee, Wisconsin, 1985. ASME paper 85-JPGC-Pwr-6.

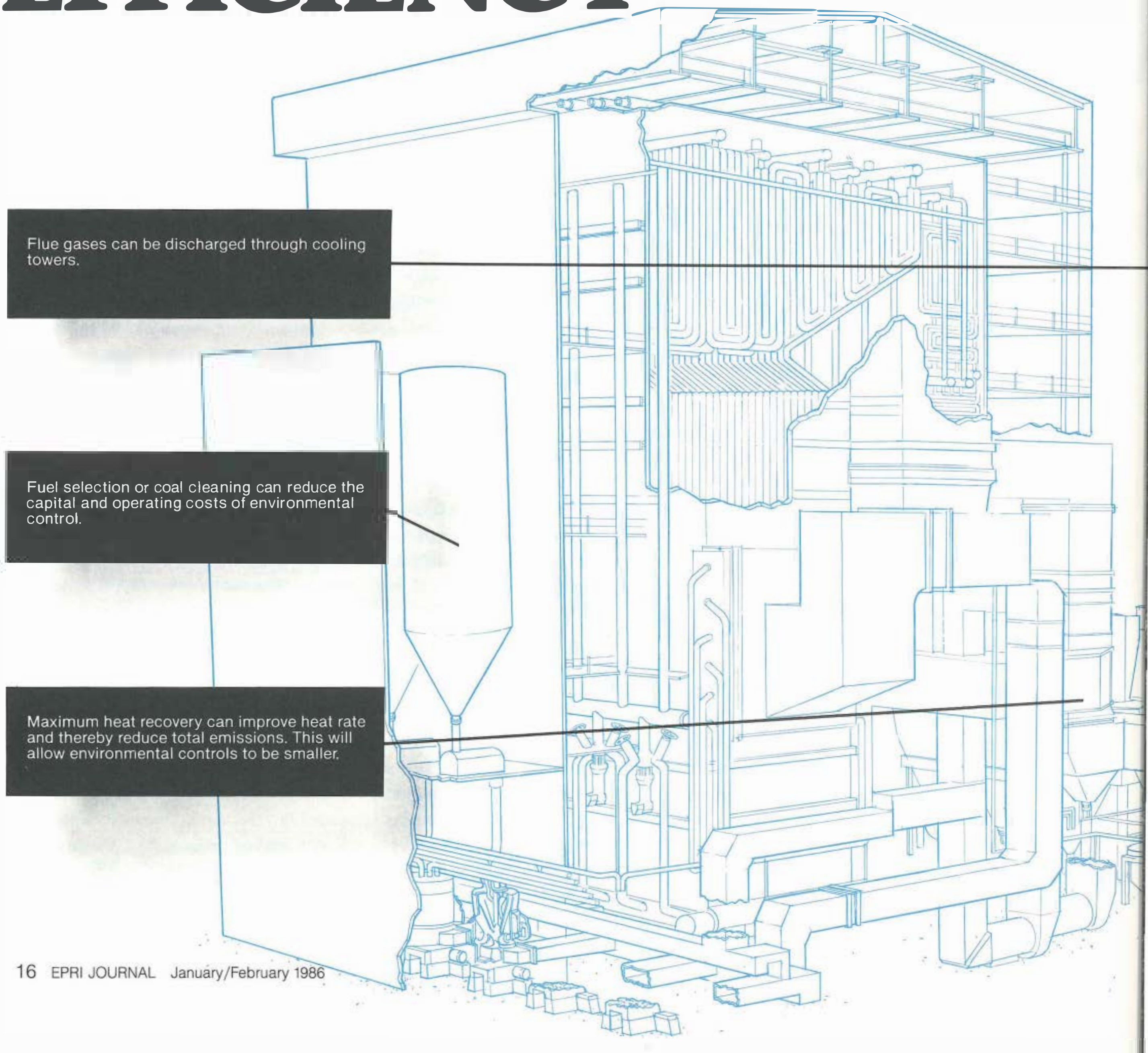
I. Fruchtman and A. F. Armor. "Supercritical Units: A Performance Report," ASME/IEEE Joint Power Generation Conference, Milwaukee, Wisconsin, 1985. ASME paper 85-JPGC-Pwr-33.

Michael Gold and Robert Jaffee. "Materials for Advanced Steam Cycles." In *Proceedings of ASM Conference on Materials for Future Energy Systems,* Washington, D.C., May 1-4, 1984.

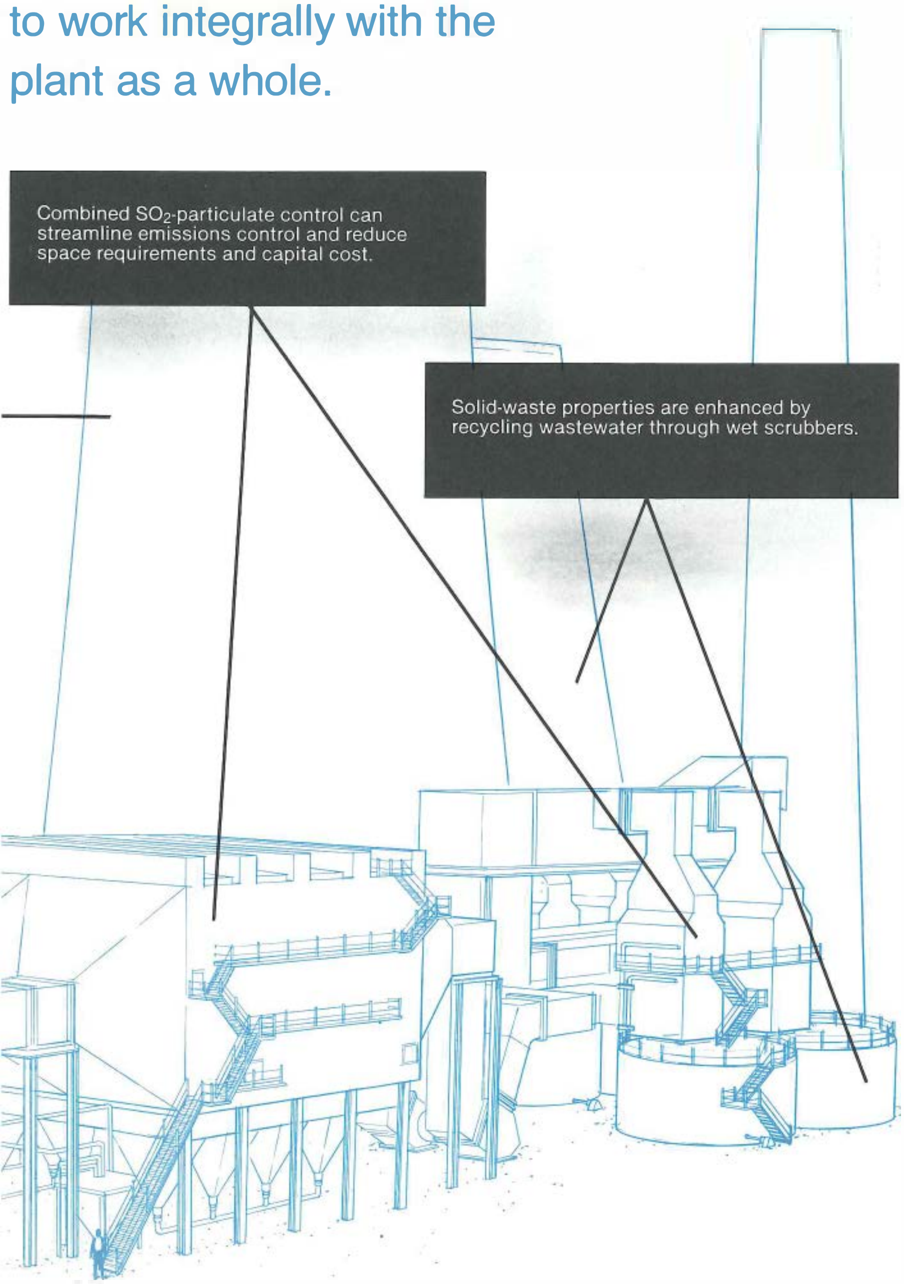
A. F. Armor, R. I. Jaffee, and R. D. Hottenstine. "Advanced Supercritical Power Plants: The EPRI Development Program." In *Proceedings of the American Power Conference,* Vol. 46, 1984.

This article was written by Michael Shepard. Technical background information was provided by Anthony Armor and George Touchton, Coal Combustion Systems Division, and Robert Jaffee, Materials Support unit.

INTEGRATING ENVIRONMENTAL CONTROL FOR COAL PLANT EFFICIENCY



The historical piecemeal addition of environmental controls has proved to be costly and inefficient. The future points to streamlining the various control functions with fewer, multipurpose components that are designed to work integrally with the plant as a whole.



Emission control requirements for power plants have grown far more stringent in the last 20 years, focusing first on air quality and then, in turn, on water issues and solid-waste management. To comply with each new level of regulation, utilities added another layer of environmental protection technology. Because environmental controls were added one after the other in response to evolving regulations, plant designers rarely had the opportunity to integrate these components with one another, the balance of the plant, and local site and fuel conditions. Consequently, they often cost more than necessary to build and operate, and they can reduce power plant efficiency and availability.

With the aim of lowering the cost of environmental systems, a design approach known as integrated environmental control (IEC) has emerged within the utility industry in recent years. The basic tenet of IEC holds that environmental controls can function most economically if they are designed integrally with boilers, turbines, and other power generation equipment.

Several years ago EPRI established an integrated environmental control program to develop integrated design strategies and evaluate their net worth for utilities. In the near term, the IEC research is studying ways to make existing technologies—scrubbers, particulate controls, waste management systems, and the like—work together better. In the long term, new devices will be developed that consolidate the functions of several of today's components into simpler, less costly systems. This approach is apparent in the improved environmental performance of all the major coal-based generation technologies, including fluidized-bed combustion and gasification–combined cycle, as well as pulverized coal.

Results from pilot plant studies completed in 1985 show that integrated design applied to conventional environmental controls on new coal-fired power plants can reduce environmental control system (ECS) capital and operating costs by up to 25% when compared with current practice. The bulk of these near-term savings are available through heat rate improvements of 100–200 Btu/kWh (from waste heat recovery and reduced auxiliary power losses), water and wastewater management, and solid-waste dewatering and disposal. For example, using wastewater instead of fresh water in wet flue gas desulfurization (FGD) processes can reduce capital and operating costs by 1–2 mills/kWh for a new 500-MW plant (mill = 0.1¢). Additionally, heat rate improvements can reduce flue gas and solid-waste production, allowing controls to be made smaller. The savings on an FGD scrubber from reducing heat rate by 100–200 Btu/kWh can total $12 million in capital and $750,000/yr in operating costs for a 500-MW plant. Greater savings may arise in the future from integrated processes currently under development, such as simultaneous NO_x–SO_2 and particulate-SO_2 control, the recycling of high-volume wastes, and the combined discharge of flue gas and cooling tower plumes.

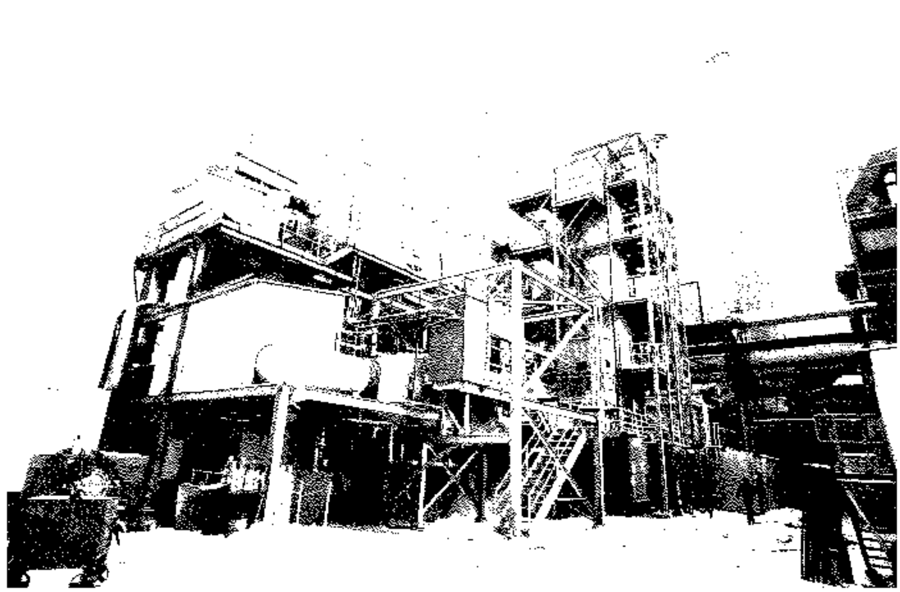
According to EPRI Project Manager Edward Cichanowicz, "To reduce costs and improve reliability, the coal-fired plant of the next decade will incorporate environmental controls as an integral part of its design and operation, rather than as a series of add-on devices. That is the central thrust of the IEC strategy."

Cichanowicz stresses that IEC includes factors traditionally viewed as external to ECS design, such as coal selection or cleaning, improvements in fuel utilization efficiency, and site selection. "Just about any plant design or operating decision that affects environmental management can and should be considered in integrated design," he explains.

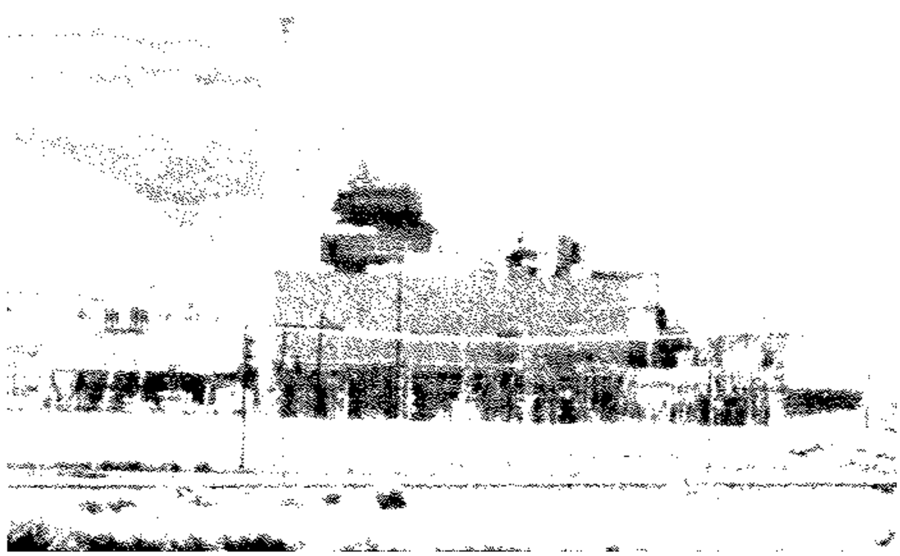
Design studies

Whatever technologies emerge in the future, utilities will still face the challenge of choosing the best environmental control approach for their specific sites. To assist in this task, EPRI funded Stearns-Catalytic Corp. to assemble industry design experience into a comprehensive IEC design strategy. According to Cichanowicz, "The strategy leads designers through a hierarchy of key questions that should be addressed if environmental quality and plant performance goals are to be achieved as inexpensively as possible." The design strategy begins with environmental control regulations, then considers fuel composition and such site features as soil hydrology and precip-

Arapahoe station



Cameo station



Testing and Demonstration Sites

EPRI's integrated environmental control pilot plant at the Arapahoe station of Public Service Co. of Colorado is equipped to test six different environmental control configurations. Findings from the pilot plant have been used to develop commercial-scale demonstration of IEC processes. Public Service Co.'s 22-MW Cameo station is the first operating plant to use dry injection of sodium-based reagent to capture both particulates and SO_2 with a fabric filter.

itation, proximity to coal sources and chemical reagents, and potential markets for by-products (e.g., fly ash).

Two significant results emerged from the design studies. First, depending on the control strategy, the cost of environmental control systems can vary from 16 to >30 mills/kWh for the same level of emissions reduction. Each control system requires different amounts of auxiliary power, chemicals, and maintenance, and it has different capabilities for duty cycling, fuel flexibility, and process control. Consequently, operating requirements should be evaluated along with cost in designing environmental control systems.

Second, the design studies showed that although coal sulfur content and the amount of flue gas SO_2 removal required are the dominant contributors to the cost of environmental controls, other fuel characteristics (such as heating value, ash content, and composition), and site characteristics (such as net rainfall, land availability, and soil properties) can offset the penalty of higher sulfur content. In combination, these fuel and site characteristics can have the same effect on ECS costs as a 1–2% reduction in sulfur. As Cichanowicz puts it, "A key lesson from these findings is that the least expensive environmental control system may not necessarily include the least expensive SO_2 removal system. It may be less costly in certain instances to install a more expensive FGD unit if it can produce savings by using low-quality water and reducing wastewater disposal costs or if it produces solid waste that can be utilized or is easier and less costly to dispose of."

During the design studies, the researchers made certain assumptions about the performance of environmental controls and cost-saving simplification measures with which the industry has little experience. For instance, the studies assumed that wet limestone scrubbers and cooling towers could operate with poor-quality water and that scrubber waste handling could be simplified to one step by stabilizing and dewatering FGD sludge with fly ash. The studies concluded that if these assumptions are sound, significant savings would arise. To validate such findings, EPRI needed a way to test the assumptions on which they were based.

Measuring IEC performance

Such testing and development are the responsibility of the EPRI-funded integrated environmental control pilot plant (IECPP), which is located at the EPRI Arapahoe Test Facility in Denver, next to the 110-MW coal-fired Arapahoe generating station operated by Public Service Co. of Colorado. IECPP draws 5000 ft^3/min (2.4 m^3/s)—the amount produced by 2.5 MW (e) of coal-fired capacity—of flue gas from the host generating station to test a broad array of environmental control devices. IECPP tests conducted by Brown & Caldwell have two objectives: to provide experience with relatively untried integrated design concepts and to define interactions between control components. Fulfilling the latter objective allows detrimental interactions to be avoided and beneficial interactions that reduce cost or improve performance to be exploited.

Six SO_2 and particulate control approaches were chosen for the initial round of study at IECPP: an electrostatic precipitator (ESP) for particulate control, followed by a wet SO_2 scrubber; a fabric filter (baghouse) for particulate control, followed by a wet scrubber for SO_2 control; a spray dryer for SO_2 control, followed by a fabric filter or ESP; and an all-dry SO_2 control system employing a fabric filter or an ESP. Testing of the first two of these configurations was completed in November 1985.

The fabric filter–wet scrubber configuration was tested first in anticipation of the approximately 10,000 MW of new capacity equipped with fabric filter–wet scrubber technology coming on-line or planned this decade (all in the western states). Working with flue gas simulating a broad range of coal sulfur levels and with various wastewater and solids-handling practices, the researchers monitored flue gas emissions and wastewater generation, studied the physical properties of the scrubber waste and fly ash, and measured the auxiliary power demands and other factors affecting power plant heat rate.

The most significant results concerned the ability of the fabric filter–wet scrubber to meet stringent water conservation and waste discharge regulations, which are characteristic of most of the West and are anticipated for some locales in the Midwest and East.

The results indicated that the fabric filter–wet scrubber configuration can successfully operate in a zero discharge mode (all wastewater either reused or evaporated on-site) and can use poor quality makeup water. With no significant effect on SO_2 removal capability, the scrubber can essentially double as a disposal system for such wastewater as cooling-tower blowdown.

Cooling-tower blowdown, which is high in total dissolved solids (TDS), is produced at the rate of 1 gal/min-MW (3.785 L/min-MW), or 720,000 gal/d for a 500-MW plant. Management of this wastewater stream can be very costly. The ability to recycle it through the scrubber reduces or eliminates the need for evaporation ponds and mechanical evaporators and thus can reduce the cost of environmental controls by 20%. These savings are particularly significant in the West, where all existing fabric filter–wet scrubber systems are located.

Different results were obtained when similar tests were conducted with an ESP–wet scrubber system, the most common particulate-SO_2 control configuration. The tests were modified to reflect conditions under which ESP–wet scrubber technology is typically applied—at plants in the East and Midwest that fire medium- and high-sulfur fuel in settings where solid-waste handling is generally of greater concern than water management. The scrubber did not perform as well with the ESP as it did with the fabric filter, particularly when the ESP was controlling particulate emissions at 0.1 lb/10^6 Btu (45 g/10^6 Btu), the level typical of existing plants where scrubber retrofits could be required. When operated in a zero discharge mode, the scrubber captured less SO_2, produced more sludge (through inefficient use of limestone), and generated solid waste that was more difficult to handle. The scrubber also was less tolerant of high TDS makeup water with the ESP than it was with a fabric filter.

These findings contradict the commonly held belief that scrubber operation is not affected by the performance of the particulate control device. Rather, they suggest that small differences in the amount of fly ash entering the wet scrubber can affect the chemistry of SO_2 removal and scrubber wastes. Although ESPs and fabric filters are both efficient particulate collectors (>99.5%), fabric filters are more effective than ESPs, especially for fine particles (<2 μm diam). The test results indicate that scrubber performance is most affected under stringent water management restrictions. When the plant was allowed to discharge wastewater, there was little difference in scrubber performance regardless of which particulate control device was in use.

A clear conclusion from this test is that plants designed to minimize wastewater discharge will benefit from very high particulate control preceding the SO_2 scrubber. This does not mean that fabric filters are necessarily preferable to ESPs, but it does mean that without significant upgrading of older ESPs at existing plants, strict control of wastewater, solids, and SO_2 may be incompatible goals.

IEC in practice

Some in the field maintain that IEC—a concept that was first formally articulated in 1979—is just a new name for a process that good architect-engineers already follow. Others assert that IEC really is a new way of approaching power plant design. Both points of view have their merits. There are no installations to point to that reflect a comprehensive IEC design effort. Nevertheless, there is evidence that the industry is taking the IEC approach seriously as it contemplates retrofits and the design of future plants.

Arizona Public Service Co. (APS) was very successful in applying IEC concepts to bring units 1, 2, and 3 of the Four Corners generating station into compliance with stringent water management regulations promulgated in the late 1970s. Prior to the enactment of these laws, the station sluiced its wastes to settling and evaporation ponds and channeled the overflow into an arroyo draining into the San Juan River.

A key to its success was the discovery that using lime to raise the pH of the scrubbers from 4.0 to 6.5 reduced scale formation and corrosion. This change increased scrubber availability and allowed ash pond water to be used as scrubber makeup. The smaller blowdown stream could then be managed onsite with evaporation ponds and a brine concentrator.

The general approach used at Four Corners—water conservation, recycling, and concentration of the final waste stream—has been applied with similar success at other zero discharge sites. The reliability and good performance of these systems may be a harbinger of future plant designs that will incorporate IEC principles from the outset.

Arthur Martinez, supervisor of resource analysis at Public Service Co. of New Mexico (PNM), believes that the day will come when IEC will be a standard part of industry practice. PNM recently used the EPRI-funded IEC design strategy to develop several designs for a future coal-fired plant. "We don't know what the conditions will be when we build our next plant," explains Martinez, "but the IEC design strategy helped us to develop cost-effective designs to meet a number of likely scenarios. With this work under our belt, we'll be able to proceed much more efficiently if and when we decide to build new capacity.

"One of the most important aspects of IEC," he continues, "is that it encourages designers to think about environmental controls along with the rest of the plant from the very beginning. This design approach has the potential to reduce capital and operating costs for environmental controls."

William Frazier, a staff engineer in Virginia Power's corporate technical assessment program, echoes these sentiments in speaking of the Arapahoe Test Facility. "It's a modest investment to avoid some very costly design errors," he asserts. "Plant designers may believe that they know how a new configuration or new component will work, but until it has been tested under real-life conditions, no one can be certain what will happen." He believes that one of the most potentially important near-term applications of IEC may be to help utilities develop space-conserving means of retrofitting SO_2 controls on existing plants. "At many stations, there simply isn't room to install a conventional scrubber. Because of its systems approach, IEC has the potential to reduce the space requirements for the whole environmental control package."

Looking ahead

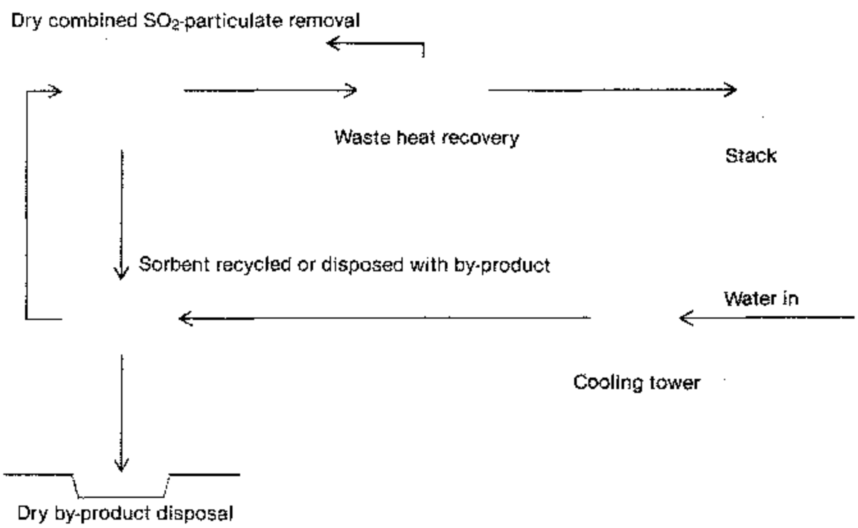
The challenge of retrofitting SO_2 controls that Frazier alludes to could become a major issue throughout the industry, depending on the outcome of acid rain legislation. If utilities have to add scrubbers to older coal-fired plants, they will want to do so in as economical a manner as possible. Results from IEC engineering studies indicate that the most economical approach to retrofitting an SO_2 removal system begins with a heat rate improvement program on the plant itself. At a typical 15-year-old 500-MW plant, for example, an investment of \$3–\$5 million to add low-excess-air burners and \$1–\$2 million to install low-leakage seals in air heaters, precipitators, and fans could reduce flue gas flow by 15% and improve heat rate up to 100–200 Btu/kWh.

Because the FGD system then will

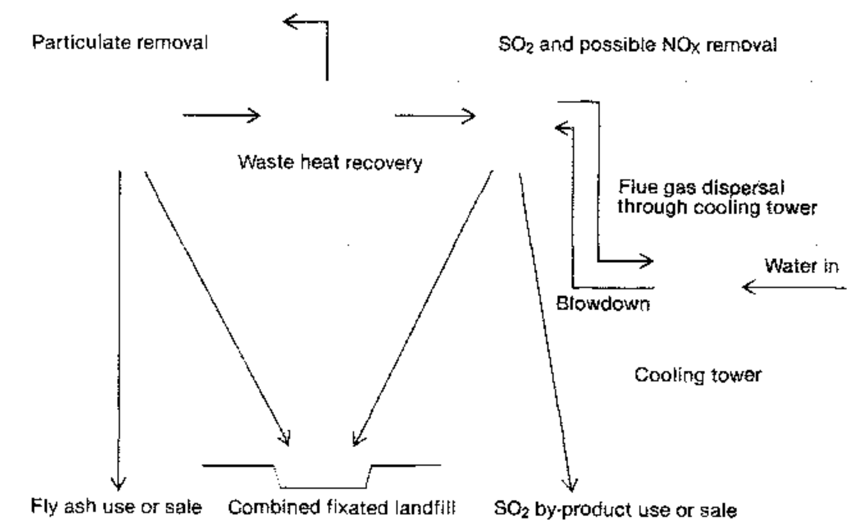
Two Strategies for Integrated Environmental Control

Depending on corporate priorities and site-specific conditions, one of several IEC approaches may be attractive to utilities. One minimizes capital cost, as well as space and water use. Another minimizes operating cost and offers high fuel flexibility and potential for by-product use or sale.

In this approach a dry or spray dry combined SO_2-particulate control process that recycles a highly reactive SO_2 removal agent is employed, producing a dry by-product. The majority of any process water required can be supplied by cooling-tower blowdown. Depending on which process is used, waste heat may be recovered to increase the plant's thermal efficiency.



In comparison with combined approaches, separate SO_2 control with limestone flue gas desulfurization has relatively lower operating cost (excluding reheat) and can accept a wider range of fuels. By-product use or sale is possible because the waste streams are produced separately. The cooling tower can be used to disperse cleaned flue gas, eliminating the need for stack gas reheat and allowing a simpler, less costly stack to be used.



have less flue gas to scrub, it can be smaller. A smaller scrubber will cost less, require less auxiliary power and chemical reagent, and produce less solid waste. Cichanowicz estimates that capital costs for the scrubber could be reduced by $12 million under such a scenario, and operating costs could fall by approximately $750,000/yr. "The saving in the environmental control system alone will pay for the efficiency upgrading," he asserts. "The fuel saving is an added bonus."

Just as heat rate improvements can reduce scrubber expenses, waste heat recovery in other areas of the plant can yield significant capital and operating savings while raising plant efficiency. Under present practice, the flue gas, which is cooled as it passes through conventional wet scrubbers, is frequently reheated with auxiliary power to give it adequate loft as it leaves the stack. Such stack gas reheating can raise the plant's heat rate 100–200 Btu/kWh and is the largest parasitic load in a typical environmental control system. Applying waste heat obtained between the particulate collector and the SO_2 scrubber could eliminate this parasitic load. Considerable work is in progress to develop this kind of waste heat application.

Another promising recommendation for avoiding the heat rate penalty of stack gas reheating is to discharge the cleaned flue gas emerging from the scrubber directly into the cooling tower. The warm, buoyant air in the cooling tower lifts and disperses the clean flue gas into the atmosphere, eliminating the necessity for a conventional stack. An experimental demonstration of this approach has been operating at the 200-MW Volklingen station in Saarbrucken, West Germany, since 1982.

There is significant potential for consolidating environmental controls into fewer, multipurpose components. EPRI has been funding development of combined SO_2-particulate controls for 10 years. For example, a 100-MW demonstration of sodium bicarbonate injection into a baghouse for combined SO_2 and

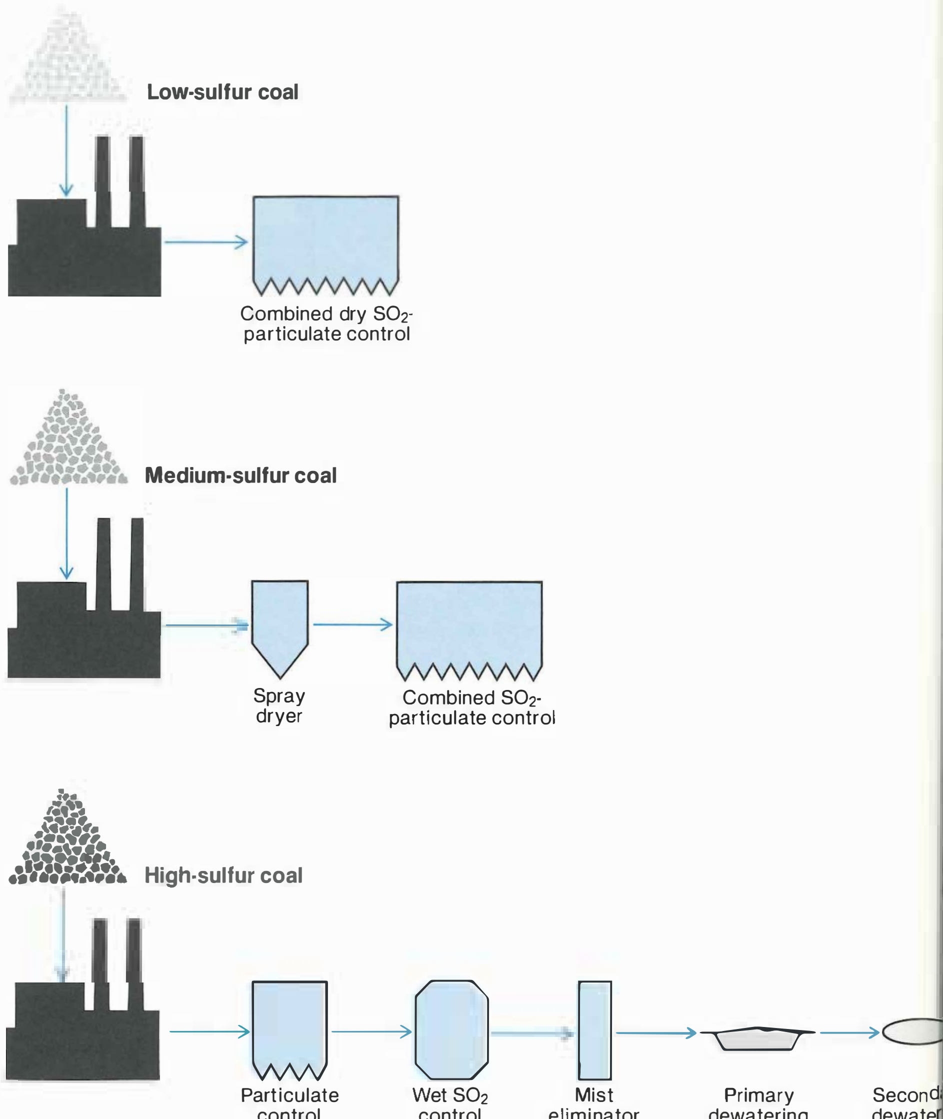
FUEL SULFUR LEVEL DRIVES ENVIRONMENTAL CONTROL OPTIONS

The most significant integration of flue gas controls commercially achievable with today's technology lies in combining particulate and SO_2 control into one function. The degree to which this integration can be economically achieved depends largely on fuel sulfur content. In general, plants burning low-sulfur coals can use consolidated particulate and SO_2 controls that cost less to build and consume less space but have higher operating expenses than the less-integrated systems best suited to high-sulfur coals.

With low-sulfur (<1%) coal, it is practical to capture particulates and SO_2 with a single device—a fabric filter using highly reactive sodium-based reagent. By eliminating the need for a separate SO_2 control component, this approach has the lowest capital cost of any available option. The sodium reagent is expensive, however, and the amount required is proportional to the quantity of sulfur dioxide that must be removed from the flue gas. Pilot-scale tests and engineering evaluations indicate that for coals containing more than 1% sulfur, such a control system may not be economical because the large amount of reagent needed drives operating costs too high.

For medium-sulfur (1–3%) coals, one of the most economical particulate–SO_2 control strategies employs a spray dryer to disperse calcium-based reagent in the flue gas. The reagent reacts with sulfur in the flue gas to form solid calcium-sulfur compounds, which are then captured along with

Sulfur content of coal is a major factor in determining the most economical environmental control approach. In general, the number of components needed for cleanup increases with higher sulfur content, in turn raising the capital costs. However, operating costs (excluding reheat) tend to decline with increasing sulfur content because high-sulfur coal is often less expensive than low-sulfur coal and the limestone reagent used in wet SO_2 scrubbers is less expensive than the sodium-based reagent used in combined dry SO_2-particulate control.



other particulates in an ESP or fabric filter. The spray dryer's capital cost is only slightly less than that of a wet limestone scrubber, but operating costs are less because flue gas reheating is reduced or eliminated, and auxiliary power requirements are lowered. EPRI also has research under way in low-temperature sorbent injection schemes that permit the same level of particulate and SO_2 control to be achieved without the capital-intensive spray dryer.

For coals with more than 3% sulfur, separate SO_2 and particulate controls are still the likely choice in most applications. This approach has a higher capital cost than more-integrated systems as it requires more components. Because it uses relatively inexpensive limestone reagent in the scrubber, the operating costs of this approach (excluding reheat) are relatively low.

Utilities can benefit from careful fuel selection analysis, considering the important influence sulfur content has on the cost of environmental controls. For applications near the economic threshold of sulfur content for spray dry and dry injection, it may be worthwhile to reduce sulfur content through fuel selection or cleaning. In other instances, it may be more economical to burn high-sulfur coal. The optimal solution for a given application depends on factors ranging from flue gas emission control requirements and plant site characteristics to fuel constituents other than sulfur, such as heating value, ash content, alkalinity, and chloride and fluoride levels. □

particulate control is being conducted at the Nixon station of the Colorado Springs (Colorado) Department of Public Utilities.

In 1986 the Institute will begin assessing the technical feasibility of more than 50 prospective processes that have been identified for combined control of NO_x, SO_2, and (in some cases) particulates. Those processes that show the most promise will undergo detailed engineering analysis and (if warranted) pilot plant testing. A number of these processes have already been developed to the stage where large-scale evaluations are under way to resolve scale-up concerns and to assess their economic viability. Two processes that have been tested employ electron beam irradiation to simultaneously collect SO_2 and NO_x from flue gas. Although these techniques require considerable auxiliary power, they produce a waste material that may have value as a feedstock for fertilizer. The elimination of waste management concerns could justify the added power the processes demand. Several other techniques, which have been tested in sizes up to 100 MW, use activated char (a by-product of petroleum refining) as a catalyst for the simultaneous reduction of SO_2 and NO_x. These technologies generate marketable sulfuric acid as a by-product.

In addition to streamlined flue gas cleanup technologies, the overall IEC strategy being pursued by EPRI and the utility industry is to develop coal-based power generation technologies that inherently combine highly effective environmental controls with improved plant productivity. Improved pulverized-coal-fired plants, as well as fluidized-bed and gasification–combined cycle units, reflect different but complementary paths to satisfying this concern for integrating environmental control functions into state-of-the-art power generation technology. These and other advanced techniques, including many under development outside the United States, will be reviewed at the Third Integrated Environmental Control Symposium in Pittsburgh, Pennsylvania, February 1986.

"Much more work will be needed to develop and test multipurpose environmental control components for future plants," comments Cichanowicz. "But early results in this area are encouraging." He adds, however, that although the development of new environmental control technologies is important, "we have to balance our long-term research with improvements in conventional systems that can be retrofitted, if necessary, into existing power stations."

Over the next four years EPRI will work with several utilities to establish full-scale commercial applications of integration concepts that were identified through the EPRI-funded IEC design studies and evaluated at the Arapahoe pilot plant. Host sites are now being sought for three retrofits and two applications in new plants. "We would like to identify some challenging retrofits with space constraints, zero water discharge requirements, and strict landfill material needs. Such conditions will allow us to demonstrate the savings available from heat rate improvements, and streamlined water and waste management practices," says Cichanowicz.

In addition to launching into commercial demonstrations of promising IEC approaches, EPRI will continue to support basic research on more-streamlined and -cost-effective environmental controls. This work is an important piece of the industry's effort to make coal-fired technology as clean, economical, and efficient as possible. ■

Further reading

Integrated Environmental Control Designs for Coal-Fired Power Plants. Final report for RP1609, prepared by Stearns-Catalytic Corp., forthcoming (February 1986). EPRI CS-4439.

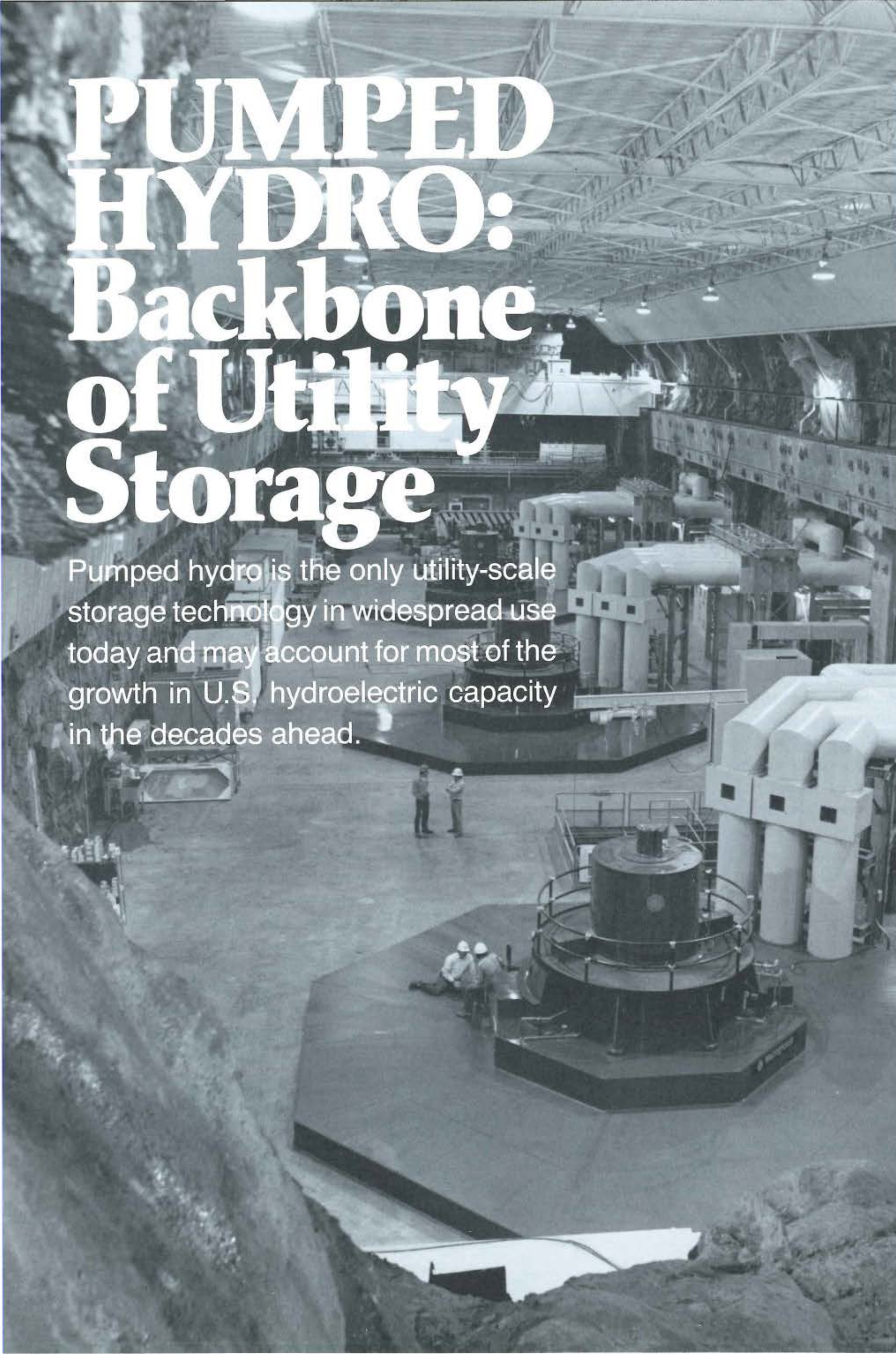
Proceedings of the Second Symposium on Integrated Environmental Controls for Coal-Fired Power Plants. Howard Hesketh, ed. The American Society of Mechanical Engineers. 1983.

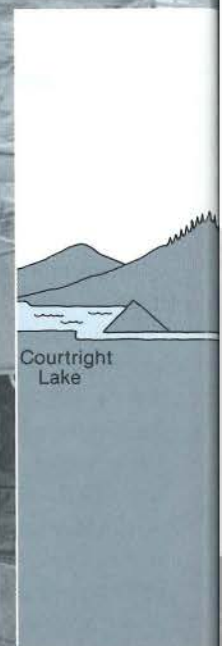
Proceedings of the First Symposium on Integrated Environmental Controls for Coal-Fired Power Plants. Howard Hesketh, ed. The American Society of Mechanical Engineers. 1981.

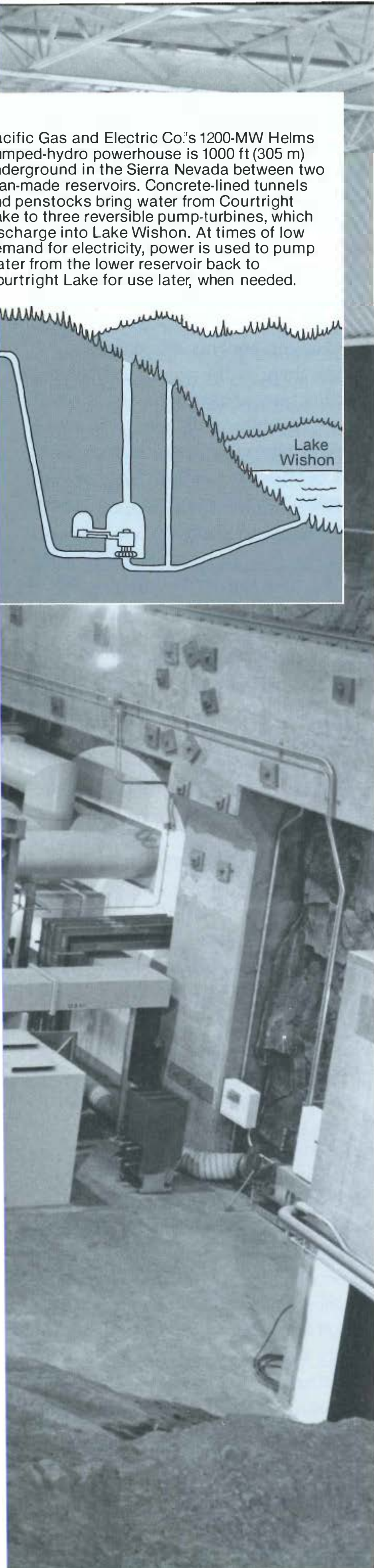
This article was written by Michael Shepard. Technical background information was provided by Edward Cichanowicz and John Maulbetsch, Coal Combustion Systems Division.

PUMPED HYDRO: Backbone of Utility Storage

Pumped hydro is the only utility-scale storage technology in widespread use today and may account for most of the growth in U.S. hydroelectric capacity in the decades ahead.







acific Gas and Electric Co.'s 1200-MW Helms umped-hydro powerhouse is 1000 ft (305 m) nderground in the Sierra Nevada between two an-made reservoirs. Concrete-lined tunnels nd penstocks bring water from Courtright ake to three reversible pump-turbines, which scharge into Lake Wishon. At times of low emand for electricity, power is used to pump ater from the lower reservoir back to ourtright Lake for use later, when needed.

Although advanced systems for utility-scale energy storage are a continuing focus of R&D, pumped hydro today accounts for nearly all the electric utility storage capacity in place around the world. In the United States, pumped hydro amounts to about 3% of total generating capacity, or some 18,000 MW; most other industrialized countries, however, have as much as three to four times the relative proportion of pumped-hydro capacity.

For about the last 20 years, energy storage has taken on growing importance to large interconnected power systems with the advent of high-capacity baseload generating plants, a widening of the difference in cost of generating peak and off-peak energy, and increasingly uncertain growth in peak demand. Use of pumped hydro has climbed because of its ability to rapidly and economically meet load requirements using lower-cost energy generated by baseload plants that are most efficient when operated almost continuously at maximum output.

Moreover, pumped storage has matured into a highly reliable and controllable technology for intermediate generation, emergency (spinning) reserve, and system regulation. Meantime, research has brought advanced storage options—such as compressed-air and battery systems—to the point of commercialization as alternatives to pumped storage when suitable sites are not available or size and economics dictate their use.

"Pumped hydro, used in coordination with load management and other storage technologies, is a key to improving the productivity and operation of utility systems," says James Birk, director of advanced conversion and storage research in EPRI's Energy Management and Utilization (EMU) Division. "Its use has grown from less than 0.3% of U.S. hydro capacity in 1960, to 7% in 1970, to about 23% today. With the introduction of deep underground pumped hydro, it could become a potentially unbounded resource. Pumped hydro likely will represent most of the growth in this country's hydroelectric generating capacity over the next few decades, provided that its full economic value is better understood and recognized, and provided that the economic risks of project construction delays and cost escalation are minimized. Although growth may not be as great as some have predicted, it is reasonable to anticipate the start of construction of another 10,000–15,000 MW of pumped-hydro capacity within this century."

With such a possible trend in mind, EPRI has initiated research efforts in pumped hydro aimed at gaining a more realistic and quantitative assessment of the value of this energy storage option and at minimizing the risks associated with expanding its potential application. Although, much like conventional hydro, the technology is generally considered technically and economically mature and not in need of major R&D attention, the utility industry's cumulative investment in pumped hydro and the expected growing need for storage capacity warrant a continuing, if only modest, R&D commitment.

Getting a head with pumped hydro

Pumped hydro works much like a conventional hydroelectric plant with the exception of its ability to operate in reverse—that is, use power to pump water to a higher elevation. A pumped-hydro plant consists of a lake or reservoir connected by shafts, tunnels, and pipes (penstocks) to hydro turbines at some lower elevation. As the energy potential of the falling water is converted to electricity by the turbines, the water flows into a second reservoir or river that is at a height differential, or hydraulic head, of from 50 to 2500 ft (15–762 m) below the upper reservoir. At times of low demand for electricity, usually overnight, lower-cost off-peak power generated by baseload plants is used to run massive pumps to send the lower reservoir's water back to the higher reservoir, thus restoring potential energy.

Such large pumps in recent decades have been mechanically integrated with turbines in the Francis-type reversible unit, which can function as either a pump or a turbine. Prior to World War II, separate pumps and turbines were used; such a configuration offers greater design and operational flexibility.

For either configuration of pumped-storage unit, the laws of physics impose an unavoidable penalty in the pump and generation cycle, making pumped hydro (or any storage technology) a net consumer of energy. Depending on the hydraulic head and plant scale, friction, evaporation, electrical, and other losses, pumped-hydro plants can consume 1.3–1.4 kWh in pumping for every kWh generated from storage. More than counterbalancing this diseconomy, however, is the difference in value between peak and off-peak power. Energy generated by fossil fuel peaking units can cost two to five times more than baseload power.

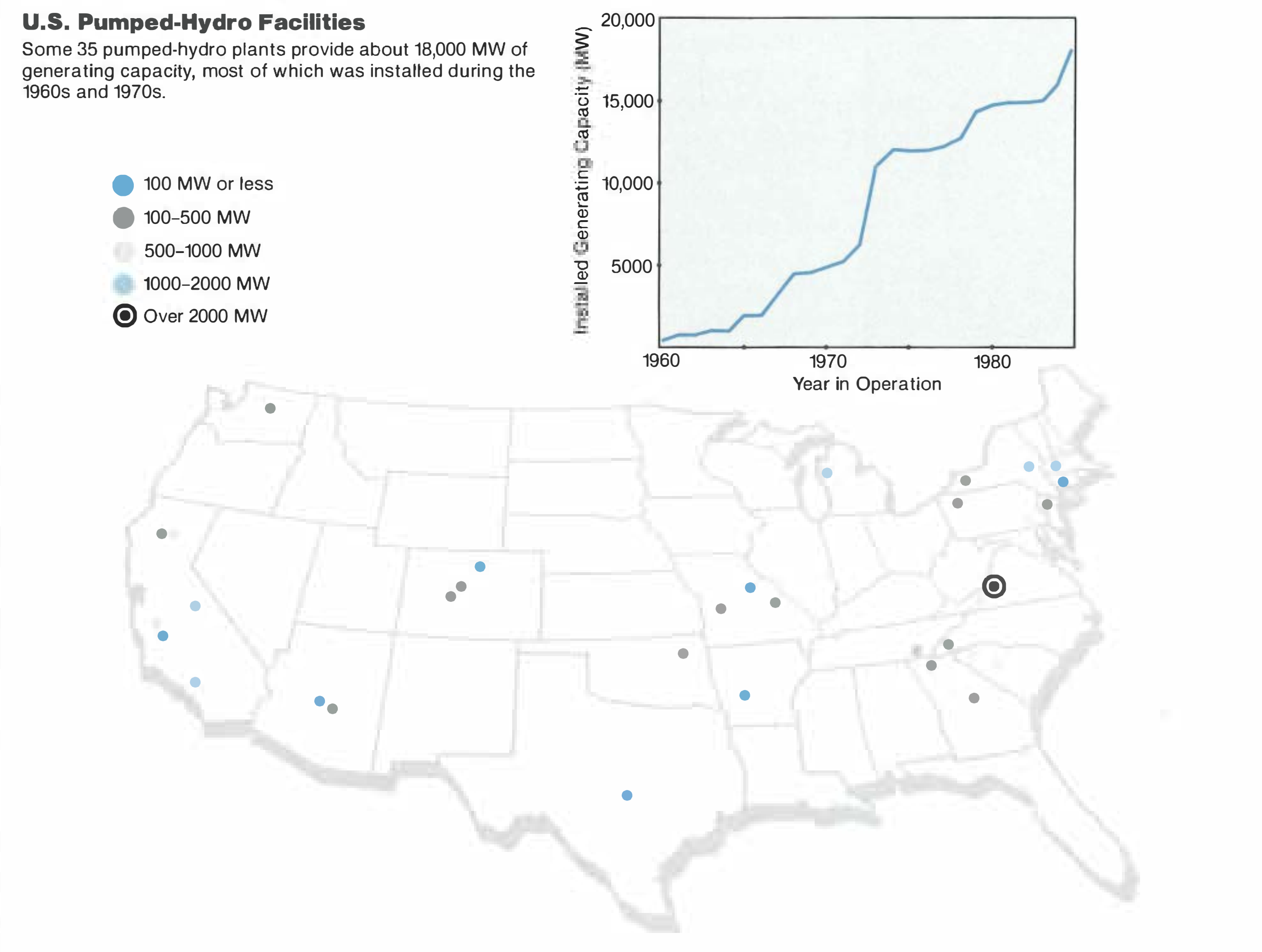
A simplistic energy-in/energy-out calculation also obscures the multifaceted value of pumped-storage capacity on many levels in a utility power system. These secondary benefits and improved methods for calculating them were explored in a 1984 international symposium sponsored by EPRI and DOE on the dynamic benefits of storage plant operation.

In addition to its value as peak generating capacity and as a means of transferring off-peak power to peak periods, an accurate account of pumped hydro's worth must include credit for the increase in capacity factor of baseload generating units and a related reduction in maintenance costs resulting from cycling baseload plants. Less cycling duty for baseload plants will also likely make their key components last longer.

Then there is the value of displaced spinning reserve capacity; with pumped storage, a utility will need less actual spinning reserve in thermal generating units because of pumped hydro's high controllability and ramp or load pickup

U.S. Pumped-Hydro Facilities

Some 35 pumped-hydro plants provide about 18,000 MW of generating capacity, most of which was installed during the 1960s and 1970s.



rate. Most large pumped hydro units—rated around 300–350 MW—can go from zero power to full power synchronized with the transmission system in a matter of minutes; it can take hours to bring large thermal units up to full load.

Many hydro storage plants are also operated remotely by system dispatchers in network control centers hundreds of miles away. In a manner similar to that of following load, hydro storage in the pumping mode can be called on by dispatchers to rapidly absorb load reductions so that thermal generating units need not be throttled back. The fast load pickup and rejection capability also makes pumped-hydro units useful to system operators in maintaining network frequency at 60 Hz.

"With pumped hydro you get the operational advantages of conventional hydro plus a lot more that is often not quantified in system planning studies or in the economic justification analyses," explains Thomas Logan, a retired veteran of nearly 30 years in hydroelectric projects with the Bureau of Reclamation. "The cost per installed kilowatt of capacity is not necessarily the bottom line. A comprehensive assessment of its economic value has to consider pumped hydro's dynamic role in the operation of the electric power grid."

Birk agrees that the value of pumped hydro in the past has often not been fully appreciated. "Because of the failure of planners to recognize the versatility of pumped hydro and optimize its size and timing, good opportunities for deploying pumped hydro have been missed. Even when they haven't been missed, the actual use of the plants by system dispatchers has exceeded planned use because the dispatcher has recognized the dynamic benefits and used the plant accordingly.

"The bottom line is this: Even after accounting for the impact of inflation, virtually every pumped-hydro plant built in the United States has provided greater economic and operational benefit than originally expected. This fact, coupled with an increasing effort by utilities and EPRI to develop improved planning tools, should overcome this lack of planning capability," adds Birk.

Fifty years of pumped hydro

Pumped hydro has been an accepted practical utility generating technology in both the United States and Europe for over 50 years, although the earliest reported application of the concept dates to 1879 when a unit was put in operation near Zurich, Switzerland. Today, there are an estimated 100,000 MW of pumped-hydro capacity worldwide, representing over 200 plants (including many multi-unit facilities) ranging in generating capacity from a few megawatts to over 2000 MW. The tally includes some 35 plants in the United States, representing about 18% of the world's installed pumped-hydro capacity.

This country's first pumped-hydro facility was the 22-MW Rocky River plant built by Connecticut Light & Power Co. on the Housatonic River in 1927. Designed to recapture some of the energy lost by early run-of-river conventional hydro plants, Rocky River has essentially been in continuous operation since 1929, although its generating capacity has since been increased to about 31 MW. The plant is now owned and operated by Northeast Utilities.

It was not until the early 1950s, however, that pumped hydro was widely recognized as a broadly applicable option for meeting peak electric loads. The resurgence in pumped hydro was aided, in part, by the development of the Francis reversible pump-turbine. The availability of such a double-duty machine led to construction of pumped-hydro projects by the U.S. Bureau of Reclamation in Colorado, by the Tennessee Valley Authority in North Carolina, and by U.S. and Canadian power authorities at Niagara Falls, among others.

By the 1960s pumped-hydro plants with generating capacities of several hundred megawatts or more were being built. As utilities gained experience and appreciation of pumped hydro's unique role as a generating resource, plant scales and hydraulic heads were increased to take maximum advantage of the potential at individual sites. When it entered service in 1972, the Northeast Utilities' Northfield Mountain plant in Massachusetts was the largest in the country at 1000 MW, rivaling Italy's 1000-MW Lago Delio plant that began operating a year earlier.

The Northfield Mountain station was the first pumped-hydro plant in which the powerhouse was built entirely underground—in this case, some 870 ft (265 m) deep within an excavated cavern. Within about a year after it began operation, two public power agencies—the Los Angeles Dept. of Water and Power and the New York Power Authority—together with Consumers Power Co. and Detroit Edison Co., joined the ranks of utilities operating pumped-hydro plants of more than 1000 MW of generating capacity in their respective service areas.

In addition to other pumped-hydro plants built since then, two large U.S. projects have recently been completed, including the new world record-holder in generating capacity. Pacific Gas and Electric Co.'s 1200-MW Helms plant on the North Fork of the Kings River in California's Sierra Nevada was commissioned in 1984, making it the largest in capacity among PG&E's 66 hydroelectric facilities. And late last year, Virginia Power placed in service the 2100-MW Bath County pumped-hydro plant—the world's largest—in a remote region of the Appalachian Mountains in northern Virginia.

PG&E's Helms plant, containing three 400-MW Hitachi Ltd. reversible pump-turbines, features the highest hydraulic head, 1700 ft (530 m), of any U.S. pumped-hydro facility. Its massive powerhouse is situated 1000 ft (305 m) underground between two man-made reservoirs that are nearly four miles apart. The northern California utility originally constructed Courtright Lake and Lake Wishon—each of which can hold about

125,000 acre-ft (154 million m^3) of water—in the 1950s as part of its conventional hydroelectric development program. More than five miles of tunnels and shafts were bored (most of them through solid granite) in recent years to connect the reservoirs with the Helms powerhouse. The plant's water tunnels and inclined penstock are concrete-lined; the penstock is 1745 ft (532 m) long and measures 27 ft (8.2 m) in diameter.

J. A. Davis, Helms project manager, says the plant can, under certain conditions, provide PG&E with dependable peaking power at full load for 19–20 days during peak demand hours (noon to 6 p.m.) before Courtright Lake, the upper reservoir, must be restocked by pumping. Typically, though, the plant is operated in the pumping mode most nights and weekends to retain a maximum 170,000 MWh of storage in the upper reservoir.

"The Helms project is a dispatcher's dream come true," reports J. Daniel Quayle, PG&E's chief system dispatcher. "It's like having 1200 MW of generation in one pocket and 1000 MW of load in the other that can be pulled out at any time. One of its big advantages is its ability to provide spinning reserve. If conditions are such that generation is not economical but spinning reserve is needed, the Helms units can be paralleled and lightly loaded, thereby saving on thermal plant startup and low-load fuel costs. Operating Helms like a bank account, we can take energy out when demand is high and return it when demand is low," Quayle adds.

Virginia Power's Bath County plant entered service late last year, following about six months' delay to repair leaks from two of three 28-ft-diam (8.5-m) power tunnels, each of which branches into two 18-ft-diam (5.5-m) steel-lined penstocks. The six penstocks bring water at a maximum head of 1262 ft (385 m) to six 350-MW reversible pump-turbines.

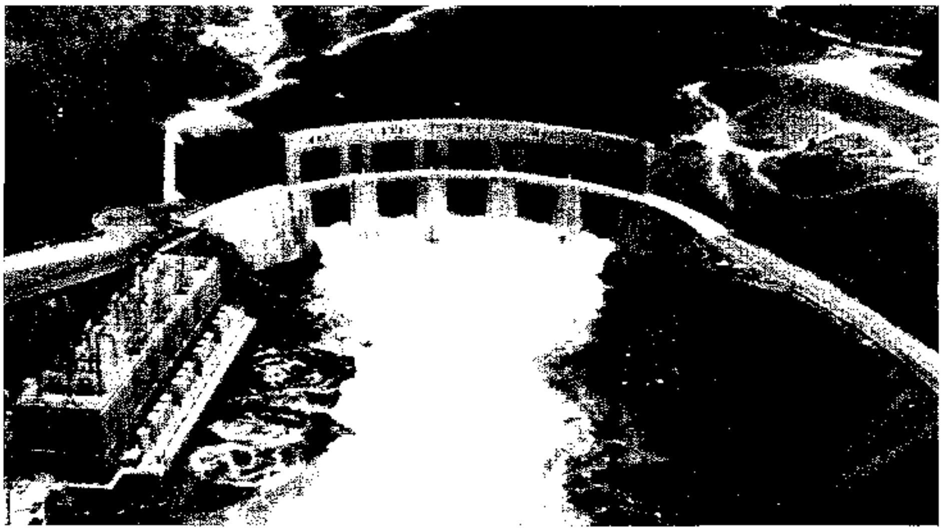
Bath County's 20-story powerhouse, one mile upstream from the lower dam, sits in a valley between man-made reservoirs on Little Back Creek (upper) and Back Creek (lower). Each reservoir has a maximum capacity of about 22,500 acre-ft (28 million m^3). When the lower reservoir is full, the 500-ft-long powerhouse alongside it is two-thirds submerged. In contrast to PG&E's Helms plant, which required the excavation of more than a million cubic yards of rock for the underground powerhouse, the Bath County plant required a like volume of concrete in its construction.

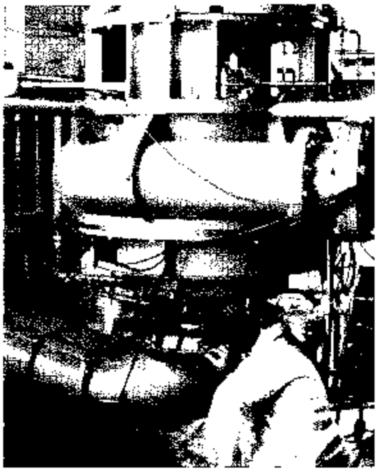
The largest of its type ever built, the $1.7 billion Bath County facility is designed for an energy storage capacity of nearly 24,000 MWh—enough to permit generation at full output for 11 h.

Elsewhere, Southern California Edison Co. reports construction is about 50% complete at its 200-MW Balsam Meadow hydro facility in the southern Sierra Nevada, only a few miles from PG&E's Helms plant. Designed to be part of SCE's existing 6-unit 800-MW Big Creek hydro complex, the $321 million Balsam Meadow plant will be operated initially as a conventional hydro plant when it enters service, which is scheduled for mid 1988. The utility plans to later upgrade the plant to pumped-storage capability; reversible pump-turbines will be installed as the original generating

Related Hydro R&D

In addition to projects specific to pumped hydro, EPRI's Energy Management and Utilization Division sponsors R&D in a number of areas related to hydroelectric generation that can benefit utilities operating, building, or planning pumped-storage plants. The work includes development of engineering guides for safety-related operation and maintenance, reliability, automation, plant uprating, and turbine cavitation mitigation, as well as new or improved equipment for measurement and testing.





High-Head Pump-Turbine for Underground Pumped Hydro

A two-stage 650-MW reversible pump-turbine is now commercially available from Hitachi Ltd. for application in deep underground pumped hydro. The 720-rpm machine can support a hydraulic head of nearly a mile. Pictured is a prototype scale model developed and tested with EPRI support.

equipment. Like the Helms plant, the Balsam Meadow plant's powerhouse is 1000 ft (305 m) underground.

Meantime, federal authorities have proposed a 2000-MW pumped-hydro complex for Lake Mead behind Hoover Dam. Nineteen southwestern utilities have joined the Western Area Power Administration, a federal power marketing agency, and the Bureau of Reclamation in a three-year, $4.8 million planning study for the Spring Canyon project. A 1982 conceptual design study by the bureau estimated the cost of the project at $1.1 billion (in 1985 dollars), not including interest and inflation during the estimated six years of construction.

The utilities—including most of the region's privately owned power companies, as well as several municipal and rural cooperatives in Arizona, Nevada, and California—have expressed interest in taking about half of the project's capacity. Preliminary studies call for three earthen dikes and one large earth and rockfill dam on the Arizona side of Lake Mead to form an upper reservoir, with Lake Mead serving as the lower reservoir. Even if plans proceed, however, construction of the mammoth Spring Canyon project probably would not be completed until the mid-to-late 1990s.

Drawbacks and environmental impact

As does any large-scale energy conversion facility, be it thermal or hydroelectric, pumped storage is not without its drawbacks and environmental impacts, although those of pumped hydro are measurably less severe than those of most other generating plants.

The principal limitation on the use of pumped hydro to date in this country has been site availability. Despite nature's provision of ample territory (from the Rocky Mountains in the west and along the Appalachian range in the east) with sufficient streamflow and hydraulic head to support pumped-hydro plant operation, many such potential sites are quite remote from load centers and existing transmission lines. Many are also among pristine surroundings. Because storage reservoirs can require significant land area, as well as experience dramatic fluctuations in water level, pumped-hydro projects have often drawn organized opposition from environmentalists and encountered substantial licensing delays.

In contrast to conventional hydro, pumped hydro typically borrows water for only a few hours, thus its effect on seasonal streamflow is less. In addition, fish kills caused when fish are forced to go through or around conventional hydro turbines can often be eliminated with pumped hydro because fish are more easily prevented from entering turbines than routed around them.

Most of pumped hydro's negative factors relate to the scale and difficulty of the civil engineering work that projects require. High construction costs and long lead times often prevail in such projects because of the understandable tendency of planners and designers to take maximum advantage of economies of scale and exploit the full hydraulic potential at available sites, which results in large-scale facilities.

The intense hydrostatic forces contained in pumped-storage power tunnels, shafts, and penstocks can, if not properly accounted for in design, lead to leakage from both conduits and reservoirs and to powerhouse flooding, or even worse consequences. A penstock section on the surface at the Helms project failed during preoperational testing, adding as much as a year to construction time. Likewise, one of the Bath County penstocks buckled during startup tests; Virginia Power and its project partners have spent millions of dollars to correct major leakage at key points in the plant.

Other problems with pumped-storage plants are similar to those of conventional hydro facilities. Generator insulation and pump thrust bearing failure are chronic problems, as is pump-turbine vibration that can occur in either pumping or generating mode. Pumped-hydro plants also experience their share of turbine cavitation damage (pitting of metal surfaces caused by pressure gradients and water phase changes), which is a major factor in reduced availability for repairs at hydroelectric facilities.

Research at EPRI

In an effort to learn from past experience, as well as to develop innovative techniques that can mitigate the technology's topographic and other environmental limitations, EPRI has funded R&D to assist utilities in preserving and improving the pumped-hydro option in this country. Most of the work is centered in the EMU division, but significant supporting elements are also found in the Electrical Systems (ES) and Energy Analysis and Environment (EAE) divisions.

One major R&D accomplishment of work already completed is expected to significantly improve the environmental siting flexibility for pumped-hydro facilities. Where natural topography does not provide sufficient hydraulic head for conventional pumped hydro, or where environmental opposition might preclude a site because of the impacts on streamflow and surrounding ecology, pumped-hydro technology could still be deployed if the lower reservoir is excavated from deep underground rock, although this variation would add significantly to a plant's capital cost.

As Robert Schainker, program manager for energy storage, points out, for underground pumped hydro to have an economic appeal comparable to that of surface storage, a plant would have to be about twice the capacity (i.e., 2000 MW) of most recently built pumped-hydro facilities and the engineered hydraulic head would have to be about twice the maximum 2500 ft (762 m) permitted with existing regulatable single-stage pump-turbine units. This means underground pumped hydro would have to have a head of nearly a mile, or about 5000 ft (1524 m), and use multistage pump-turbine units.

Until recently, there were no regulatable pump-turbines commercially available that could operate under such head and associated pressure. Some single-stage units, according to Schainker, could support a head of 2500 ft (762 m), but a 5000-ft head required development of a multistage machine. Such a unit is now commercially available as a result of EPRI R&D support in 1983 and 1984 of design and model testing by Hydraulic Turbines, Inc., a joint venture of Hitachi Ltd. and General Electric Co. The design was based on detailed analytic and materials studies that led to a prototype scale (6.5:1) model, which was then subjected to extensive analysis and testing.

The resulting two-stage 650-MW pump-turbine machine, operating at 720 rpm (twice the speed of conventional pumped-hydro units), has a component design efficiency of just over 90% in both pumping and generating modes, which is comparable to that of 500-m-class single-stage machines. Its high speed permits a surprisingly small physical size (10-ft-diam runner), although this design feature brought an added materials challenge because of the increased potential for vibration and cavitation. The use of high-quality, well-machined stainless steels in major moving parts of the unit is among the features designed to meet these challenges.

Model testing of the high-head machine was so successful, research managers report, that Hitachi is commercially offering the unit with a 3–5-yr warranty for the first buyer. According to Antonio Ferreira, former manager of the Northfield Mountain pumped-hydro project and now a consultant to EPRI in the hydroelectric generation field, "Hitachi's warranty offer, which is substantially better than the warranties offered for most conventional hydro generating units, represents a high degree of confidence on Hitachi's part, as well as a willingness by the manufacturer to share the risks with a utility to develop a site that would make use of the high-head pump-turbine."

EMU also manages a number of projects under the division's hydroelectric

World's Largest Pumped-Hydro Plant

Virginia Power's Bath County pumped-hydro plant, recently completed in a remote region of the Appalachian Mountains, is the world's largest pumped-storage facility at 2100 MW of generating capacity. The 20-story powerhouse is two-thirds submerged when the lower reservoir is full.

program that have direct application to pumped hydro. These include a major study of hydroelectric plant reliability, guides for civil engineering, plant modernization and model testing, development of acoustic and other flow measurement techniques, and monitoring methods for predictive maintenance.

In other pumped-hydro-related research at EPRI, the EAE division and several utilities and universities have jointly developed a computer program for chronologically simulating hourly unit commitment and load dispatch for power systems. The BENCHMARK code, scheduled for release early this year, offers a significant improvement over traditional dispatch simulation methods that use load duration curves in that it can more accurately represent ramp rate limitations and other factors on thermal generating units, as well as provide close accounting of available energy storage capacity (i.e., the water level in a storage reservoir).

The ability to integrate these variables over time in dispatch simulation and to project their effects at some future time is expected to allow more-effective and economic use of peak generating units, including storage capacity. Such improvements will, in turn, enhance the value of storage in a utility system.

EPRI's ES division manages R&D in a number of areas relating to rotating machinery and other plant electrical equipment aimed at improving reliability and economic operation of all types of turbine generators, including hydroelectric units and their pump-turbine cousins. ES is also sponsoring development of a comprehensive, multivolume plant electrical equipment reference book (to be issued later this year) that will include sections specific to pumped hydro.

New initiatives

The EMU division has undertaken several new initiatives in R&D aimed at improving the design, siting, construction, operation, and maintenance of pumped-hydro plants, whether on the surface or underground. Last year, Morrison-Knudsen Engineers was chosen as the contractor to survey and study construction experiences at existing pumped-storage facilities. The goal is to identify lessons learned in past projects that can help utilities building new plants in the future to minimize construction costs and lead times while maintaining conservative design margins. Researchers will consider design, construction, procurement, and acceptance testing practices to identify recurring problems and suggest appropriate remedies.

In a related project being conducted under the direction of Tor Brekke, a professor of geological engineering at the University of California at Berkeley, researchers are addressing design criteria for high-pressure tunnels and shafts with the goal of developing guidelines. Significant emphasis will be given to studies of case histories involving existing facilities.

Brekke, who brings to the work considerable experience and background in such design from his native Norway, where most of that country's hydro plants are deep within mountains, notes that the frequent dynamic loads in power tunnels associated with pumped-hydro operation demand special consideration. "Pressure load fluctuations caused by the pumping and generating cycles can loosen what might otherwise be stable rock in unlined tunnels. Stabilization measures for those loads must therefore be somewhat more conservative than for conventional hydro generation."

Adds Schainker, "Tunnel excavation and construction are a big part of the capital cost of pumped-hydro, underground pumped-hydro, or even underground compressed-air storage. In the past, this area has been the most risky in terms of significant cost overruns. Our research will try to get a better handle on how to build large excavated caverns and tunnels. Although improved methods are available, they have not been widely used yet." Reports on results of the improved design strategies for pressure tunnels and shafts are expected to be issued later this year.

EPRI also plans to take a fresh look at site evaluation methods for pumped storage. R&D proposals are being sought from potential contractors for an 18-month effort to develop site screening guidelines that will help utilities evaluate and compare numerous potential sites and conduct first-order cost-benefit analyses in less time and at less expense than are typically involved. "Right now there is no standard methodology for evaluating one site against another," notes Schainker. "We intend to give utilities an assessment approach that covers the planning, cost analysis, and site selection from *A* to *Z*."

Energy storage systems provide utilities a hedge against uncertain future customer loads, financial and economic conditions, and fuel costs. "Storage systems have economic benefit to utilities under almost any scenario one can envision," says Birk. "Based on half a century of proven experience and the present lack of incentives for the utility industry to risk deployment of new storage options, pumped hydro will remain the backbone of utility energy storage for many years to come." ■

Further reading

Vansant, Carl. "High Tech Hydro: An Overview of Pumped Storage," *Hydro Review*, Vol. 4, No. 2 (summer 1985), pp. 38–45.

Proceedings of the International Symposium and Workshop on the Dynamic Benefits of Energy Storage Plant Operation. Boston, Massachusetts, May 7–11, 1984. DOE–EPRI.

U.S. Department of Energy. *Survey and Analysis of Selected Jointly Owned Large-Scale Electric Utility Storage Projects.* Prepared by Battelle, Pacific Northwest Laboratories, May 1982. PNL-4124.

Preliminary Design Study of Underground Pumped-Hydro and Compressed-Air Energy Storage in Hard Rock, vols. 1–13. Final report for RP1081-1, prepared by Acres American, Inc., for Potomac Electric Power Co., May 1981. EPRI EM-1589. DOE/ET 5047-1.

This article was written by Taylor Moore. Technical background information was provided by James Birk and Robert Schainker, Energy Management and Utilization Division.

Unit Commitment Model Saves $500,000 a Year

An improved system for scheduling generation commitment is helping KPL Gas Service achieve significant savings. Called FULSCH, the system is a computer model developed by Boeing Computer Services Co. as part of an EPRI project aimed at helping utilities make better use of fuel resources by scheduling deliveries, maintaining stockpiles, and dispatching units more efficiently. By using the optimal generation schedules developed by FULSCH, KPL Gas Service engineers were able to shave about $10,000 a week off their fuel costs. The FULSCH programs are designed to be transportable from one computer system to another and to adapt to individual utilities' information needs. ■ *EPRI Contact: Charles Frank (415) 855-2299*

New Turbine Performance Test Is Cheaper, Easier

With a new turbine performance test developed by the ASME and demonstrated by General Electric Co. under EPRI contract, utilities will be able to run acceptance tests on new turbines and to reassess turbine performance in existing plants over the plant lifetime. Previous ASME acceptance tests using the full ASME test code were complex and quite expensive—up to $500,000 for a $20 million turbine. The new alternative test procedure can cut that cost by as much as 80%. After a recent test by Wisconsin Power & Light Co. based on ASME and General Electric data, it was estimated that the new test procedure saved about $400,000. And the ease with which the test can be conducted is an additional benefit in terms of the ongoing assessment of turbine performance. ■ *EPRI Contact: Thomas McCloskey (415) 855-2655*

Model Simplifies Plant Lifetime Calculations

A microcomputer spreadsheet for modeling the economics of remaining plant lifetime is expected to save Baltimore Gas & Electric Co. over $60,000 this year. The result of EPRI-funded research, this scaled-down computer model disaggregates a complex cost function into more easily analyzed components, reducing the time and expense required for data preparation and calculation. This is a bonus for utilities who have performed their plant retirement, upgrading, and remaining-lifetime analyses with production cost models, whose expense and complexity have discouraged more broadly scoped analyses. In contrast, the spreadsheet shortcut can be calibrated with as few as two runs of a full-scale production cost model and has enabled BG&E to expand its analysis scope and save money. The utility has run a number of detailed sensitivity analyses, varying such factors as fixed costs, plant availability, and purchased power costs, and expects to use the minimodel in a variety of other economic evaluations. ■ *EPRI Contact: Dominic Geraghty (415) 855-2601*

FGD Improvements for Zero-Discharge Plant

Zero-discharge power plants using scrubbers for flue gas desulfurization (FGD) are often beset by a number of chemical problems, including excessive limestone use, plugging, and poor solids handling. To learn more about the chemistry problems of FGD systems and the probable effects of operating with minimum water use, EPRI undertook a study of wet limestone FGD system chemistry and operation at three zero-discharge plants. One of these plants suffered from severe scaling and was unable to consistently meet federal SO_2 emission requirements. On the basis of EPRI's FGD study evaluations and comparisons, the utility was able to select the most efficient options to solve its scaling problem: upgrading the limestone grinding circuit, using a higher-quality wash water for the mist eliminators, and adding dibasic acid to the scrubber liquor. Although research indicated that the use of dibasic acid could have achieved the required emission levels by itself, it would have increased the plant's operating costs (including purchased power) by some $2.5 million a year. EPRI's recommendations, in contrast, boosted SO_2 removal to the required levels and saved the utility $300,000 a year in operating costs because of increased efficiency in limestone use and reduced scaling. In addition, the entire plant system reliability was increased by more than 25%. ■ *EPRI Contact: Dorothy Stewart (415) 855-2609*

UFIM Model Reduces Fuel Inventory Costs for Consumers Power

Using an EPRI-developed analytic tool called UFIM (utility fuel inventory model), Consumers Power Co. has changed its inventory policy at four of its five plants and is saving an estimated $500,000 a year at one plant alone. The utility's decision to take another look at its fuel inventory practices resulted from the increasing costs associated with managing fuel inventories: nationwide these had increased from $1.2 billion to over $9 billion in less than a decade. Traditional fuel inventory decisions were based on such factors as company history, experience, and intuition. In the unpredictable fuel supply climate of the 1980s, quantitative tools are needed as well. Consumers Power agreed to help test UFIM, a methodology and modeling system that can perform formal cost-benefit analyses of various plant factors and can be easily adjusted to specific utility systems. With UFIM a utility can balance the costs of holding larger inventories (which ensures against emergencies) against the costs of maintaining smaller inventories (which risks reduced fuel burns). In addition to the estimated savings at its Whiting plant, Consumers Power expects cost benefits at its four other generating sites. ■ *EPRI Contact: Stephen Chapel (415) 855-2608*

Decision Analysis Aids Alabama Power's Fuel Planning

Uncertainties in fuel prices and supply have complicated the long-term procurement strategies of many utilities. Planners have been forced to look for tools to help them assess the results of long-term versus short-term fuel contracting and to quantify the risks and costs associated with these approaches. To help them, EPRI funded research to develop methods that apply standard decision analysis techniques to traditional fuel-planning problems. Recently a task force from Alabama Power Co. and Southern Company Services, Inc., used these techniques to help Alabama Power make two important coal procurement decisions, decisions that the utility estimates will save it $650,000 a year over a two-year period. The task force identified variables that were critical to the company's operations, such as its energy requirements and its already committed coal supply, and then used in-house interviews to establish probability distributions for each. These distributions served as input for a decision tree program that yielded a range of possible coal needs and a probability assessment for each need. Not only did the analysis lead to substantial savings for Alabama Power, but it supported the utility's decision to retain short-term contract flexibility in ordering coal supplies. ■ *EPRI Contacts: Stephen Chapel (415) 855-2608; Howard Mueller (415) 855-2745*

UPM Integrates Information for Long-Range Planning

Utility planners in the 1980s no longer enjoy the predictable operational climate that characterized earlier decades. Today utility executives are called on to address new questions, assimilate new and varied information, and assume widely different responsibilities. And while input from a host of specialists is available to them, they have had no easy or straightforward way to integrate this information at a level of detail and consistency sufficient for meaningful answers or solutions. Seeing that a new generation of modeling tools was needed that could keep pace with the growing complexity of operations, EPRI initiated a cooperative effort between Arthur Andersen & Co. and Commonwealth Edison Co. to develop an integrated, flexible model for long-range decision making. The result, the utility planning model (UPM), is a highly integrated corporate strategic tool that simulates all major utility functions and can rapidly produce complex corporate financial and engineering reports. UPM's flexibility and ability to handle detail have earned it acceptance: already Commonwealth Edison has used the model to address regulatory questions and to weigh the effects on customers of including various types of plants in the rate base. Savings to the utility in 1984 alone are estimated at about $150,000. ■ *EPRI Contact: Victor Niemeyer (415) 855-2744*

Guide Makes Load Forecasting Easier for Small Utilities

Most small utilities have traditionally lacked the staff and financial resources to employ modern, complex mathematical and statistical forecasting tools, making it difficult for these utilities to document their forecasts for financial and regulatory agencies. By identifying appropriate forecasting tools and demonstrating their adaptation for easy use, *Residential Load Forecasting for Small Utilities, Volume 1: Reference Guide* (EPRI EA-3805) enables small utilities to prepare long-term residential forecasts. A clear definition of the forecasting process and step-by-step instructions help the reader develop explanatory (econometric) forecasting models. Covering econometric modeling and end-use analysis, the guide is designed for use by relatively inexperienced utility staff members. Information on forecasting software packages, survey forms, and procedures for data collection are included in appendixes. Volume 2 comprises case studies describing how four rural electric cooperatives have adapted and used the techniques. This second volume includes discussion of some problems encountered in specific applications and proposed solutions. ■ *EPRI Contact: Steven Braithwait (415) 855-2606*

EPRI's Third Employee Completes Administrative Career

David Saxe's forty-plus years of government and industrial operations management were concentrated on the business side of R&D.

David Saxe, EPRI's senior vice president of finance and administration, retired in December 1985 after 13 years in charge of the Institute's business operations. He is retaining a consultant's role with Floyd Culler, EPRI president. Alex Fremling, formerly of the Nuclear Power Division, has assumed the duties of Saxe as a group vice president.

Saxe was EPRI's third employee, joining Chauncey Starr, the founding president, and R. L. Rudman, Starr's staff assistant, in May 1973 when the Institute's operating history was no more than a program outline, a press conference on goals, a letterhead, and one meeting with the Board of Directors.

As director of administration, Saxe organized and directed all EPRI's support services, notably its guidelines and practices for R&D contract negotiation and management and its financial controls.

Saxe graduated in economics from the University of Chicago in 1936. His true career began early in the 1940s, when he became budget director for an agency of what is now the federal Department of Housing and Urban Development. From 1947 to 1961 he was with the Atomic Energy Commission, first as budget director for development contracts and later as deputy manager of AEC's Chicago office. He joined Atomics International in 1961 as director of administration for Starr, then president of the company, and he later became vice president for operations, remaining in that post until Starr again sought him in 1973.

Although the EPRI divisions and departments that reported to Saxe are central to the Institute's operating success and, in particular, to its stewardship of funds, Saxe himself maintained a low profile during most of the past thirteen years. EPRI became well known as a force in the R&D community during that time, but few people realize that it is now the largest nongovernment research management organization in the world.

Saxe is quietly proud of many practices and de facto policies that he was able to introduce and encourage in contract administration. Examples include EPRI's high proportion of cost-shared R&D and its provisions for auditing contractors' books. These, and the closely coupled procedural steps in EPRI's cycle of program planning and project approval, drew Saxe's close attention as ways to ensure the best use of member utility R&D funds.

Two years ago he figured strongly in making EPRI's case for the technical competence of any bidder (not that of U.S. bidders alone) as the criterion for EPRI's award of R&D contracts. At issue were the economic interest and understandably strong conviction of several domestic companies and a state regulatory body. Saxe worked patiently and intensely, on both East and West coasts, in a drawn-out series of meetings and hearings to resolve the matter.

Although firm in his ethical convictions, Saxe is refreshingly soft-spoken and gentle. Many EPRI staff members sought his personal guidance, as well as that of his office. Starr, now director of EPRI's Energy Study Center, who has probably known Saxe the longest, recently said of him: "Dave's exposure to technical staff reviews over the years has given him a lot of insight. His judgment on technical programs is sound and worth listening to. He's as close to a statesman in these areas as anyone we have.''

Fremling Named to Head EPRI Business Operations Group

Fulfilling plans presented by President Culler last October, Alex Fremling succeeded David Saxe on January 1 as vice president of finance and administration. He joined EPRI in August 1984 as director of administration for the Nuclear Power Division, and he worked as an assistant to Saxe during the final two months of 1985.

Fremling came to the Institute from Richland, Washington, where he had been manager of the Department of Energy operations office since 1973 and its deputy manager the preceding year. Fremling's responsibility included the 570-mi^2 Hanford site with $5 billion in facilities, an annual budget exceeding $900 million, a payroll of 13,000 people, and the work of eight major industrial contractors.

AEC and its successor agencies were Fremling's employer for 27 years, beginning in Washington, D.C., in 1957. He worked in the Chicago operations office from 1958 to 1965, and from 1967 to 1972 he was in Washington again, mostly as special assistant to James Ramey, a commissioner of AEC.

Fremling is from Minnesota. He graduated from Carleton College in government and international relations, and he later earned an MA in political science at the University of Minnesota.

New Director for Communications

Richard Claeys became the director of EPRI's Communications Division November of 1985. The announcement was made by R. L. Rudman, group vice president for industry relations and information services, who had been acting director throughout the year.

Claeys has been in corporate public relations since 1964, successively with Connecticut General Insurance Corp. and the Metropolitan Life Insurance Co., where he was vice president for corporate communications for six years. His responsibility at Metropolitan Life included both internal and external communications.

As EPRI's communications director, Claeys guides the public information department, the *EPRI Journal*, and a staff that produces printed materials, films, tapes, and exhibits for audiences both inside and outside the utility industry. His work includes consultation with individuals of the EPRI executive staff, with trade and industry groups, and with communications directors of member utilities.

Joining EPRI marks a return home for Claeys, who formerly lived in the San Francisco Bay area and graduated from St. Mary's College of California. He subsequently received an MS in journalism from Boston University.

Larger EPRI Board Increases Industry Representation

Reasoning that 24 members afford far greater visibility and opportunity for utility participation than the current 15 members, EPRI's Board of Directors amended its bylaws to that effect on December 11, 1985. Nominees for the nine new positions will be presented at the next Board meeting in April 1986.

Enlarging the Board makes it possible for CEOs from utilities of more varied size and in more regions to take part in EPRI policy setting and government.

CALENDAR

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

MARCH

17–19
Hydro O&M Workshop and Seminar: Life Extension
Washington, D.C.
Contact: James Birk (415) 855-2562

18–20
Steam Turbine Blading
Los Angeles, California
Contact: Thomas McCloskey (415) 855-2655

19–21
PWR Primary Water Chemistry and Radiation Field Control
Oakland, California
Contact: Christopher Wood (415) 855-2379

APRIL

21–22
Optimizing VAR Sources in System Planning
Washington, D.C.
Contact: Neal Balu (415) 855-2834

MAY

13–14
Reducing Cobalt in Nuclear Plant Materials
Seattle, Washington
Contact: Howard Ocken (415) 855-2055

JUNE

2–4
Conference: Life Extension and Assessment of Fossil Fuel Power Plants
Washington, D.C.
Contact: Barry Dooley (415) 855-2458

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

UPGRADING COALS BY OIL AGGLOMERATION

Increased attention has been given recently to beneficiation of low-quality and/or low-rank coals. Low-rank U.S. coals are generally considered to be low-quality fuels. Subbituminous coal and lignite are high in moisture, high in oxygen, low in heating value, often high in ash, and their extremely reactive nature causes numerous handling problems. Of these concerns, the high moisture content is probably the greatest and contributes to, or is the cause of, the other concerns. Conventional drying of these coals to lower the moisture content, however, makes them even more reactive and increases their inherent propensity for spontaneous combustion. (Conventionally dried coal returns essentially to its original moisture content on exposure to air and moisture.) These coals are prime candidates for cost-effective upgrading that would decrease the moisture content without increasing reactivity. EPRI research in the Clean Liquid and Solid Fuels Program addresses the beneficiation of low-rank U.S. coals through several approaches, one of which is oil agglomeration.

Oil agglomeration is a process that has been successfully applied to bituminous coal and coal-cleaning-plant tailings. Coal, water, and oil are intensively mixed and then separated to yield de-ashed coal-oil agglomerates and an ash-rich water slurry (Figure 1). Low-rank, high-oxygen coals have traditionally been considered unsuitable for beneficiation by oil agglomeration because petroleum distillates (e.g., diesel fuel), which agglomerate bituminous coals, do not work with the lower-rank coals. Experiments at the Alberta Research Council, however, show that bridging liquids (oil additives), which are composed mainly of heavy oils and some light oils, are very efficient in agglomerating subbituminous coals (RP2147-10).

The heavy oils that have been used successfully are tars, pitches, heavy crudes, bitumen, and their higher-boiling components. These heavy oils contain oxygen, nitrogen, and sulfur heteroatomic-functional groups that are adsorbed onto the hydrophilic (oxygen) sites of the subbituminous coals to form agglomerates. Identifying these heteroatom-containing heavy oils as viable bridging liquids was the result of extensive research on the structure and nature of these low-rank coals.

The upgrading of coal by oil agglomeration is based on differences between the surface properties of the coal and its impurities. The organic material in coal is generally hydrophobic. Except for pyrite, the inorganic coal constituents are hydrophilic. When coal, oil, and water are mixed together, the organic coal particles become coated with a thin layer of oil and form stable agglomerates. The inorganic impurities remain suspended in the aqueous phase but rapidly settle out.

In this work on low-rank coals, the agglomeration of the organic material is accompanied by removal of the coal-bound water, which is replaced with oil. A major objective of the oil agglomeration process is the reduction of the moisture content of the product to the lowest possible level. A reduction in moisture content both improves heating value and significantly lowers the cost of shipping.

Experimental procedure

The Alberta Research Council carried out oil agglomeration experiments with two U.S. subbituminous coals, Wyodak and Kemmerer. The coals were crushed and then combined with selected bridging liquids. Bitumen, heavy oil, and coal tar were each mixed with light additives, and each mixture was individually tested as the bridging liquid. Coal was mixed with

Figure 1 Coal-oil agglomerate. The spherical shape of the particles is a result of the agglomeration process; agglomerates may vary in terms of size, depending on the length of processing.

Table 1
AGGLOMERATION TESTS WITH U.S. SUBBITUMINOUS COALS

	Wyodak Coal	Kemmerer Coal
Bridging liquid		
Constituents	Heavy oil, diesel oil	Bitumen, diesel oil
Quantity (wt%, moisture-free coal)	14.9	20.8
Feed coal		
Moisture content, as-received coal (%)	21.2	17.7
Moisture capacity (%)	29.3	20.6
Ash content, dry basis (%)	7.1	5.4
Heating value (Btu/lb)	9,230	10,260
Agglomerate		
Moisture content, after air drying (%)	3.9	4.5
Moisture capacity, average value (%)	21.0	14.0
Ash content, dry basis (%)	5.4	3.3
Heating value (Btu/lb)	11,740	12,780

water to achieve the required solids concentration and then combined with a bridging liquid in a stirred tank. The agglomerates were collected, washed, and dewatered by using screens. They were subsequently drained and analyzed for particle-size distribution, moisture, ash content, oil content, heating value, and moisture capacity. Finally, the agglomerates received various thermal treatments to recover the low-boiling oil components.

Table 1 shows the results of agglomeration experiments performed with these two U.S. subbituminous coals. The experimental conditions were selected on the basis of a large number of prior tests performed with Canadian coals of different ranks. (The conditions were naturally occurring pH, ambient temperature, a particle-size distribution of 100% below 0.6 mm, a mass-median diameter in the range of 0.2–0.3 mm, a solids concentration of 30% on dry coal, and intense agitation at 1700 rpm.) The bridging liquids were bitumen and heavy oil admixed with diesel oil or kerosene. The properties of both the low-rank coals and the oils governed the selection of the bridging liquids.

The recoveries of coal matter and bridging liquids were close to 100% for all experimental tests on U.S. subbituminous coals. Because the coals were low in ash to start with, beneficiation, in terms of de-ashing, was slight. (Similar tests using high-ash Canadian subbituminous coals gave about 50% ash rejection.) However, the tests indicated a significant decrease in the moisture content of air-dried agglomerates, compared with moisture in the raw coal.

An increase in bridging-liquid concentration had a very limited influence on the reduction of ash content. Apparently, the degree of liberation of mineral matter from coal during comminution determines the extent of de-ashing. Ash content in the range of 5.4–6.0% for the agglomerates is probably within the optimal range of values that can be achieved for this particular degree of comminution. More-advanced or severe grinding may increase the extent of de-ashing, but this would entail an increased consumption of bridging liquid.

Oil agglomeration also significantly lowered the moisture capacity of the subbituminous coals. (Moisture capacity is the equilibrium moisture at 20°C and 95% humidity.) Differences in the moisture capacity of agglomerates generated with different bridging liquids and at different oil-addition levels were significant. Moisture capacity of raw Wyodak coal was 29%. Oil agglomeration without heat treatment reduced this value to the 20–22% range. Agglomeration tests with Kemmerer coal yielded similar results, reducing the moisture capacity from 20.6% to 14%.

In the case of Kemmerer coal, the oil consumption was significantly higher than that in the Wyodak agglomeration tests. Kemmerer coal has five times more surface area and close to three times more cumulative pore volume than does Wyodak coal. To obtain agglomerates of comparable size, therefore, a higher amount of bridging liquid is needed with Kemmerer coal.

Oil recovery

During the agglomeration of coal, the bridging liquid is adsorbed onto the surfaces of the coal particles, displacing water. Because the cost of oil is estimated to account for a substantial portion of the cost of the agglomerated product, the partial recovery of the oil from the agglomerates could have a beneficial effect on the economics of the process.

Oil recovery tests were conducted at temperatures of 250, 300, and 350°C (Table 2) under a slight vacuum (800 mbar; 80 kPa). A mixture of bitumen and diesel oil was used in a 1:1 ratio to generate the agglomerates from Wyodak subbituminous coal. The initial oil content in the agglomerates was 16% (on a dry basis). Rapid heating recovered considerable amounts of the oil from the agglomerates. At 350°C the entire amount of consumed diesel oil and an additional 28% of the bitumen evaporated and condensed. Heat treatment at the same temperatures resulted in recovery of 19, 44, and 64% of the total bridging liquid, respectively. Further, there was no accom-

Table 2
OIL RECOVERY TESTS

	Untreated Agglomerate	Test 1 (250°C, 10 min)	Test 2 (300°C, 10 min)	Test 3 (350°C, 10 min)
Oil recovery (%)				
Diesel oil	NA	37.8	88.6	100.0
Bitumen	NA	0	0	27.9
Total oil	NA	18.9	44.3	63.9
Product characteristics				
Moisture content (%)[1]	4.5	1.9	1.9	1.6
Moisture capacity (%)	14.0	7.4	6.3	5.2
Ash content (%)[2]	3.6	3.7	3.7	4.2
Volatile matter content (%)[2]	49.0	47.2	44.2	41.7
Fixed-carbon content (%)[2]	47.3	49.2	52.1	54.0
Heating value (Btu/lb)[1]	12,780	13,190	12,910	13,070

Note: These tests involved heat treatment under reduced pressure (80 kPa).
[1]After air drying.
[2]Dry basis.

panying reduction in heating value of the agglomerates.

Possibly of greater importance is the fact that the moisture capacity of the treated agglomerates was reduced significantly as a result of the heat treatment. The moisture capacity of raw Kemmerer coal was 20.6%, and oil agglomeration reduced moisture capacity to 14.0%; heat treatment gave a further reduction of moisture capacity to 7.4, 6.3, or 5.2%, depending on the treatment temperature.

Results

Research performed for EPRI on U.S. low-rank coals provided a fundamental understanding of coal upgrading. Beneficiation of these coals is primarily a matter of removing moisture without causing undesirable changes in the coal. Commercial (i.e., thermal) coal-drying techniques make these coals prone to self-heating. Oil agglomeration, however, can produce low-moisture, low-moisture-capacity fuel with a heating value similar to that of bituminous coal. These coals can be transported after drying without reabsorption of water.

The results of the experiments indicate that spherical agglomeration is quite promising, under certain conditions, for beneficiation of low-rank coals. In addition to beneficiation, agglomeration also provides a means of recovering combustibles from the waste streams of various industries. In particular, coal fines from washeries could be recovered by waste oils and, conversely, oils in the tailings of tar sand and oil sand operations could be agglomerated by coal fines or coke. All these possible industrial applications await development of the agglomeration technology.

EPRI is continuing the work in oil agglomeration by extending the successful results with subbituminous coals to lignites and is evaluating the economics of the improved value of the coal versus the cost of processing. EPRI is also investigating other nonthermal methods of upgrading coal to provide both fundamental understanding and feasible methods of beneficiation. *Project Manager: L. F. Atherton*

SUBSTRATE MATERIALS FOR CATALYTIC COMBUSTORS

*Nitrogen oxide (NO_x) emissions from stationary gas turbines can be controlled in various ways. The method most widely used at present is injection of steam or water into the combustor. This process reduces the NO_x emissions of low-nitrogen fuels from 200–400 parts per million (ppm) to 50–100 ppm. The Japanese have developed a postcombustion process called selective catalytic reduction (SCR) that reduces NO_x in gas turbine exhaust gases. The SCR process can reduce NO_x levels to less than 10 ppm. The main disadvantage of SCR systems is their high cost, reportedly as much as \$80–\$120/kW. A potentially more economic way to reduce NO_x emissions to fewer than 10 ppm is to use catalytic combustors. Catalytic combustors operate at temperatures below 1600°C (2900°F), at which little or no NO_x is formed. An earlier R&D status report (*EPRI Journal, *March 1985, p. 39) discussed the combustion aspects of catalytic combustors. This report reviews EPRI-sponsored testing of two commercially available substrate materials to evaluate their potential for use in catalytic combustors (RP-1657-2).*

The key component of a catalytic combustor is the reactor. It consists of a ceramic honeycomb cylinder, generally 350–400 mm (14–16 in) in diameter and 50–100 mm (2–4 in) long. The honeycomb material, which provides a large surface area for the catalyst, has 300–500 openings (cells) per square inch in the axial direction and very thin walls, 0.15–0.2 mm (6–8 mils). The catalyst, generally a platinum alloy, is bonded to the walls of the substrate by a porous ceramic coating. The ceramic structure is packaged in a high-temperature metal structure (can).

Service conditions of catalytic reactors are very severe. The major requirements are (1) reliable operation at 1260–1400°C (2300–2550°F) for at least one year; (2) resistance to severe thermal shock cycles during normal and emergency startups and shutdowns (the combustor may have to withstand as many as 300 thermal shock cycles during the life of the catalyst); and (3) minimal loss of catalytic activity over the lifetime of the catalytic reactor.

Small components (50 mm [2 in] in diameter) operated for brief periods (up to 1000 h) have demonstrated the ability of catalytic reactors to provide low-NO_x combustion. However, these tests did not demonstrate the physical and mechanical properties needed to estimate the ability of large catalytic reactors to meet service requirements. EPRI therefore initiated RP1657-2 to measure the relevant properties of the two most promising high-temperature substrate materials commercially available. Researchers determined the materials' ability to withstand thermal shock cycles similar to those encountered in service. They also determined the effect of long-term isothermal aging on catalytic activity. Results indicated that both substrates and catalysts require substantial improvement.

Test materials and approach

Ceramic honeycomb catalyst supports are widely used in automotive exhaust systems to reduce CO and NO_x emissions. The substrate material is cordierite, a magnesium aluminum silicate. A mixture of kaolin and talc is extruded into the required honeycomb shape and fired at high temperatures to form cordierite. Cordierite is desirable because of its low thermal expansion; its thermal expansion coefficient is 0.2×10^{-6}/°C. This characteristic provides excellent thermal shock resistance. Unfortunately, cordierite cannot be used in gas turbine combustors because it melts at 1445°C (2650°F).

For high-temperature applications, such as diesel exhaust filters, the substrate industry has developed a family of compositions based on aluminum titanate. The thermal expansion of this material is low but also very anisotropic. This characteristic leads to the development of microcracks, which reduces the thermal expansion further but also reduces the material's strength. Aluminum titanate is therefore combined with other low-expansion materials, such as mullite ($2\ Al_2O_3 \times 1\ SiO_2$), to form a strong thermal-shock-resistant body.

For the present study, researchers selected two aluminum titanate–based materials produced by the two leading substrate manufacturers, Corning Glass Works in the United States and NGK in Japan. The Corning product was a 72% mullite–28% aluminum titanate composition with a thermal expansion coefficient of $0.5–1.9 \times 10^{-6}$/°C and a melting point above 1700°C (3100°F). The NGK product was a magnesium dioxide–aluminum titanate–titanium dioxide composition, with a thermal expansion coefficient of 0.5×10^{-6}/°C and a melting point also above 1700°C.

Both products are manufactured by extrusion and sintering to provide honeycombs with 400–600 cells per square inch and a wall thickness in the range of 0.15–0.2 mm (6–8 mils). For the EPRI project, substrate wheels 225 mm (9 in) in diameter and 100 mm (4 in) long were assembled by cementing smaller segments together. The substrates were then coated with a proprietary ceramic and a noble metal catalyst by the Engelhard Corp. Researchers carried out the following major tests to judge the durability of the coated substrates.

- Thermal cycling test. This test closely approximates a normal startup and shutdown cycle of a catalytic combustor designed by Westinghouse Electric Corp.
- Catalytic combustion test. This test uses the same cycle as the thermal cycling test and uses the catalyst-coated substrate as a combustor. It is more severe than the thermal cycling test because of the existence of axial and diametric thermal gradients in the substrate.
- Isothermal-aging tests. Tests of 1000-h duration at various temperatures determine po-

Figure 2 Thermal cycle used to simulate normal startup and shutdown sequence of the Westinghouse-designed catalytic combustor.

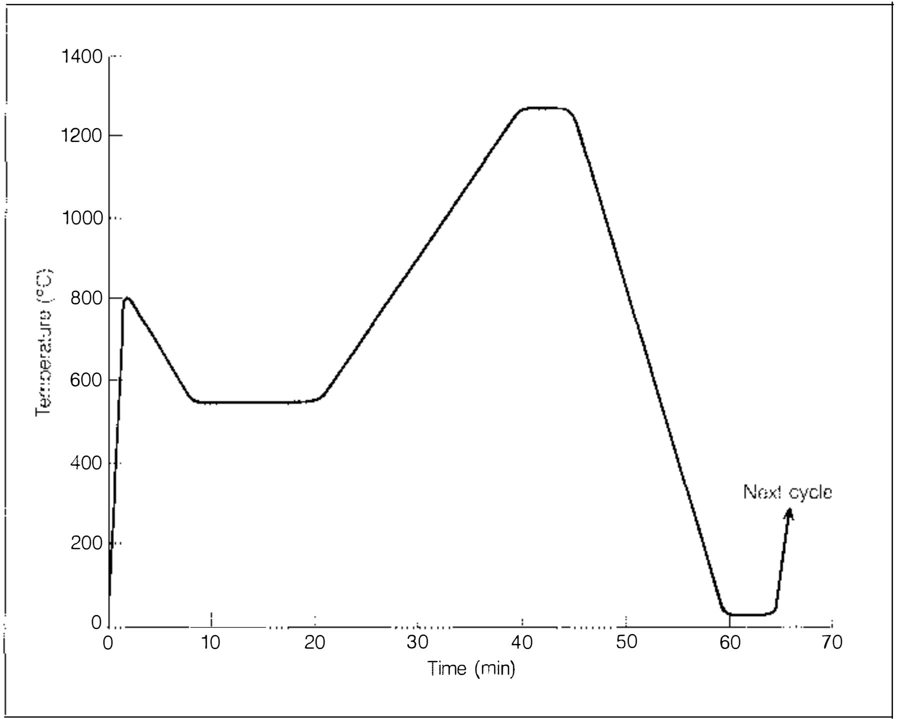
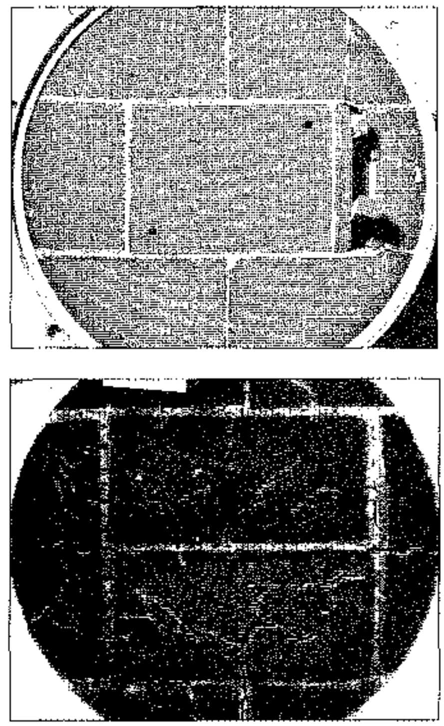


Figure 3 NGK substrate (top) and Corning substrate (bottom) after 65 cycles in thermal shock test.



tential loss of catalytic activity that results from catalyst sintering.

Test results

The thermal cycling test, conducted at the Engelhard combustion facility, used the cycle shown in Figure 2. The test plan called for subjecting the catalyzed substrate wheels to 300 cycles. Thermal cracks were first noted in the NGK material after 22 cycles. After 65 cycles, material losses became significant and the test was stopped. Figure 3 (top) shows the failed substrate. Posttest analyses indicated thermal ratcheting as the probable failure cause (i.e., during each thermal cycle the substrate material expanded permanently). After 65 cycles the material expanded linearly a total of 4%. This permanent expansion probably increased the stresses in the substrate enough to crack it. The strength loss after 65 cycles was 62.5%.

The Corning material started to crack after 45 cycles, and this test was also terminated after 65 cycles. Figure 3 (bottom) shows the condition of the substrate after testing. Posttest analysis indicated that the cracks were confined mainly to the surface. The strength of the crack-free interior actually increased 15%. Permanent expansion during the thermal cycles was 1.9% linear, less than that of the NGK material but still too high. Separate laboratory tests indicated that the Corning material's thermal expansion coefficient also increases during thermal cycling.

The combustion test confirmed that both substrate materials were not sufficiently resistant to thermal shock. The NGK material failed after 4 cycles because it cracked and lost catalytic activity. The Corning material survived the 10-cycle test without serious loss of catalytic activity. However, the substrate was severely cracked throughout. Its condition prevented researchers from determining its strength after the test.

A catalyst's activity depends on its surface area. During long exposure at high temperature, individual catalyst particles may sinter and coalesce, which decreases surface area and catalytic activity. To investigate possible catalyst deactivation, researchers isothermally aged catalyzed substrate materials at 893°C (1600°F), 1095°C (2000°F), and 1260°C (2300°F) for 1000 h and measured catalytic activity before and after aging. They found no serious loss of catalytic activity after aging at 893° and 1095°C. After the aging at 1260°C, however, the gas inlet temperature had to be raised by 50° to 450°C to cause ignition, indicating some loss of catalytic activity.

In addition to the deficiencies they found in the simulated service tests, researchers discovered other areas that needed improvement in tests to determine physical and mechanical properties for stress analysis and design calculations. The NGK material had a high creep rate at both 1095°C and 1260°C. The aluminum titanate in the Corning material partially decomposed when held at 1095°C for 1000 h, which decreases the resistance to thermal shock in this critical temperature range.

Investigators concluded that the best substrate materials for high-temperature use now commercially available need considerable improvement to survive service in catalytic combustors of large land-based gas turbines, where they are exposed to a very high steady-state operating temperature (1250–1400°C, 2300–2550°F) and must simultaneously withstand repeated thermal cycles during startups and shutdowns. Whether currently available materials based on aluminum titanate will be able to perform satisfactorily is somewhat doubtful. Therefore, EPRI plans to begin a long-range exploratory program that will identify and develop alternative substrate materials for future use in catalytic combustors. Because the development of a complete catalytic combustion system will probably take 5–10 years to complete, the target for combustor service temperature has been increased to 1400°C (2550°F) to match the anticipated increase in turbine inlet temperature in the next 10 years. *Project Manager: W. T. Bakker*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

LEANING STACK LINERS

Freestanding brick stack liners that develop a leaning problem are of great concern to the utility industry. The leaning seems to occur in liners downstream of wet flue gas desulfurization (FGD) systems. EPRI has surveyed the industry to characterize the severity of the problem and to document known causes and preventive measures (RP1871-13). Also, associated research at specific sites is being conducted to identify the physical and chemical mechanisms responsible (RP2248-3). According to results from the survey, approximately 20% of the brick liners in stacks downstream of wet FGD systems have some degree of lean. Repairing or replacing a stack liner can be a large capital expense; to date, two utilities have elected to make major modifications to their brick stack liners because of lean problems.

Freestanding brick stack liners are common in the U.S. utility industry; over 200 are currently in use. Figure 1 shows some of the design features of a stack. To provide protection against sulfuric acid condensate formed in the stack when flue gas cools, a liner is built of acid-resistant red shale or fireclay brick with a potassium silicate mortar. The annular space between the concrete shell and the liner is commonly pressurized to reduce the migration of gas through the liner.

Before the incorporation of wet FGD systems upstream of stacks, the conditions of service for these liners were fairly uniform. The temperature of the flue gas was in the range of 220–320°F (104–160°C), with relative humidities close to that of the ambient air. The addition of FGD systems has significantly changed the service conditions encountered in stacks. With FGD operation, flue gas can range from about 120°F (49°C) and totally saturated to various higher-temperature, lower-relative-humidity conditions that are determined by the extent and method of reheating used. When the FGD system is completely bypassed for some reason, the earlier, pre-FGD conditions prevail (320°F maximum temperature, near-ambient humidity).

Normally, the temperature of the saturated gas exiting the FGD system is raised by some 30–50°F (17–28°C), either by bypassing a portion of the hot flue gas around the FGD system or by reheating the FGD outlet gas. Reheating can be done either directly with heating coils in the main flue gas stream or indirectly by injecting an externally heated gas stream into the FGD outlet gas. The reheated flue gas is unsaturated when it enters the stack, but the amount of condensation upon cooling within the stack is greater than it was before the incorporation of FGD systems. In addition, the flue gas can contain entrained droplets of absorbent liquor from the FGD system, which can settle on and penetrate the liner walls. Depending on the FGD process type, this carryover exposes the brick and mortar in the liner to sulfite and sulfate compounds, usually in combination with calcium, magnesium, or sodium cations.

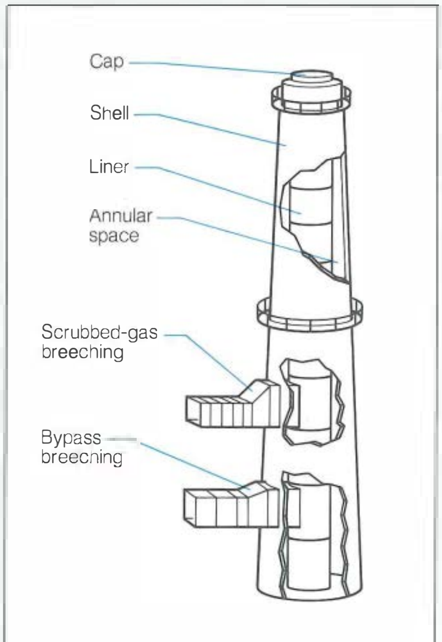


Figure 1 Stacks for coal-fired power plants have freestanding liners of brick. Leaning liners are a problem in some stacks downstream of FGD systems—especially in the type shown here, in which cooler, treated flue gas is mixed and heated with hot, untreated gas. EPRI research is aimed at understanding this problem.

Background survey

The first task of RP1871-13 was to survey the industry to determine the extent of the problem. Of over 200 brick-lined stacks, it was determined that 66 were downstream of FGD systems on units of at least 200 MW in size. Six of these units reported leans of more than 1 ft (30 cm), and six reported less severe leans. Thus, nearly 20% of the brick-lined stacks in service downstream of FGD systems reported leans of some degree, and about 10% reported major leans. (According to discussions with brick liner constructors, a lean of 1 in/100 ft of stack height is not unusual in a new stack.) A lean is manifested as movement of the top of the stack toward the shell and visible skewing of the stack cap. The principal concern is that the liner will contact the stack shell and cause structural damage.

The brick-lined stacks downstream of wet FGD systems can be classified into four FGD system/ductwork/stack configurations, which define the service conditions anticipated in the liners. Figure 2 illustrates these four basic configurations.

In configuration 1, all the flue gas is treated by the FGD system and reheated. Stack liner temperatures are generally 150–190°F (65–88°C), and the flue gas is unsaturated. In configuration 2, a portion of the flue gas is bypassed around the FGD system and recombined with the treated flue gas before entering the stack. Configuration 3 is like configuration 2 except that the gases are remixed within the stack rather than in the FGD outlet ductwork. For configurations 2 and 3, the gas conditions in the stack can range from scrubbed 115–135°F (46–57°C) saturated gas to 150–320°F (65–160°C) unsaturated gas, and there can be

Figure 2 Stacks downstream of FGD systems can be classified into these four configurations. An EPRI survey to assess the problem of leaning stack liners has yielded the following data on units of at least 200 MW: configuration 1, 13 total units, no leaning liners; configuration 2, 34 units, 1 liner with a major lean (> 12 in), 5 with minor leans; configuration 3, 12 units, 5 liners with major leans, 1 with a minor lean; configuration 4, 7 units, no leaning liners.

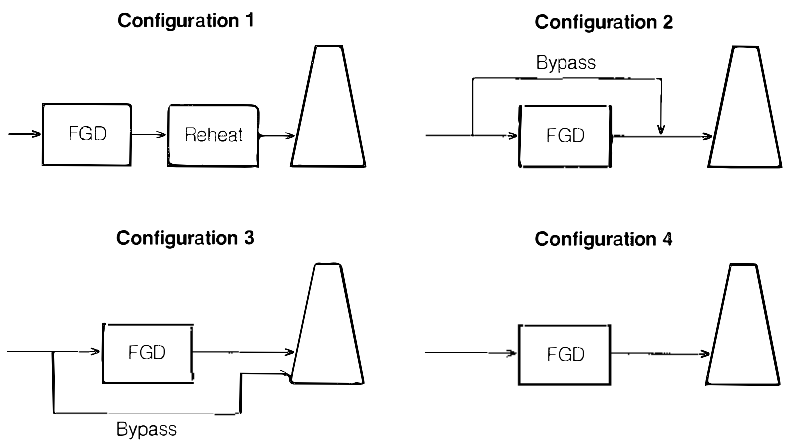


Table 1
UNITS WITH LEANING STACK LINERS

Unit and Utility	Unit Configuration	Stack Height (ft)	Service Time (yr)	Amount of Lean (in)	Direction of Lean
Southwest-1, Springfield (Mo.) City Utilities	3	385	6	27[a]	Spiral, away from breeching
Marion-4, Southern Illinois Power Cooperative	3	400	6	24	Toward breeching
Thomas Hill-3, Associated Electric Cooperative	3	620	2½	24[b]	Toward breeching
Gibson-1, Public Service Co. of Indiana	2	500	2½	20	Toward breeching
Dallman-33, Springfield (Ill.) Water, Light, and Power Dept.	3	500	4½	19	Toward breeching
A. B. Brown-1, Southern Indiana Gas and Electric Co.	3	500	6	18	Spiral, away from breeching
Jeffrey-1, Kansas Power & Light Co.	2	600	6½	6	Not available
Coal Creek-1, Cooperative Power Association	2	650	6	6	Not available
Coal Creek-2	2	650	5	6	Not available
Laramie-2, Basin Electric Power Cooperative	3	600	4	6	Not available
Tombigbee-2,[c] Alabama Electric Cooperative	2	400	6½	4	Toward breeching
Tombigbee-3[c]	2	400	5½	4	Toward breeching

[a] Lean before the liner was rebuilt.

[b] Corrective action subsequently reduced this lean to 10 in, the same as it had been after 1 year of service.

[c] The Tombigbee Unit 2 and Unit 3 liners are in the same shell.

considerable fluctuation over time, depending on the quantity of gas being bypassed. In configuration 4, no reheat or bypass is used and the gas in the stack is 115–135°F (46–57°C) and saturated at all times. No leaning liners have been reported in units of configuration 1 or 4. Half of the units having configuration 3 have reported leaning liners.

Leaning liners

Once the units were categorized according to configuration, the investigation was directed to those brick liners where major leans were reported. Table 1 presents some data on the leaning liners. Because the majority of the severely leaning liners are in configuration-3 units, the conditions associated with this arrangement may contribute to leaning. All the liners with major leans are made of red shale brick; several of those with minor leans are made of fireclay brick. High-sulfur-coal applications account for all the major leans, although several minor leans have been reported with low-sulfur-coal applications.

Core samples from the Gibson, Dallman, and Thomas Hill station liners are being analyzed in an attempt to identify a mechanism causing the leaning. Both physical and chemical analyses are being performed.

Several utilities have independently taken action to alleviate their leaning-liner problems. At its Southwest Unit 1, Springfield (Missouri) City Utilities dismantled and rebuilt the entire liner. It used fireclay brick instead of red shale brick, changed suppliers for potassium silicate mortar, and pressurized the annular space between the shell and the liner. Whereas the original brick liner had developed a lean of 27 in (68 cm) in six years of operation, the new liner has not shown any lean in nearly two years of operation.

At Southern Indiana Gas and Electric Co.'s A. B. Brown Unit 1, a separate brick liner was retrofitted inside the existing liner for the bottom one-third of the stack. No additional lean has been reported. A. B. Brown Unit 2 (which began operation last fall) uses the same, inner-liner-type design; in addition, the top portion of the liner is not freestanding but is supported by the concrete shell through ring girders.

Associated Electric Cooperative has instituted a counterweighting remedy for the leaning brick liner at its Thomas Hill Unit 3. The liner had shown a lean of 10 in (25 cm) after a year of service and 24 in (60 cm) after 2½ years of service. By installing a band around the liner near the top and using two separate pulley systems to apply a force of 36,000 lb (16,300 kg) in the direction opposite the lean, in three months the lean was reduced from 24 to 10 in. The utility intends to keep the counterweights in place.

Possible mechanisms

There is a very strong indication that differential effects are involved in leaning. Whether these thermal effects are operating via physical or chemical means remains unknown.

A stack liner can be subjected to differential thermal effects in several ways. When a unit is shut down, the liner temperature falls nearly to ambient temperature. Personnel at Southwest-1 report that in the early operating days after the lean was first noticed (after approximately one year of service), the lean would recover nearly 6 of the 10 in (15 of 25 cm) when the unit was taken off-line and would increase again when the unit was restarted.

A second cause of thermal differential occurs when the FGD scrubber is temporarily bypassed and the stack is subjected to a full flow of hot gas instead of scrubbed saturated gas or partially reheated scrubbed gas. Many of the units with early FGD installations were allowed to bypass the FGD system in an emergency or if it malfunctioned. This meant that the brick liner was subjected to rapid temperature fluctuations on a cyclic basis. During the early operation of Southwest-1, for example, when the lean developed, it was not unusual for FGD system problems to necessitate bypass directly to the stack. At the same time the Southwest liner was rebuilt, the utility (in an unrelated action) instituted a practice that has significantly stabilized FGD system operation—the addition of dibasic acid to the scrubbing liquor. The greater temperature stability within the rebuilt liner may contribute to its improved performance.

A third cause of thermal differential is poor mixing of the gas stream in the stack, which can lead to thermal gradients across the inner surface of the brick liner. This seems to be the case in configuration-3 stacks: sending hot bypass gas and cooler saturated gas into the stack liner via separate breechings must necessarily result in thermal gradients within the stack. To a lesser degree, poor mixing of these two streams in the FGD outlet ductwork (configuration 2) can result in thermal gradients within the stack liner.

There are several theories about how thermal gradients could cause the leaning problem. One involves physical properties. Both brick and mortar expand upon heating, and preliminary analyses indicate that the thermal coefficient of expansion is larger for mortar than for brick. This would not be relevant to leaning if the stack liner were exposed to a uniform temperature around its circumference. Thus, it does not apply to the first two situations described above, unit shutdown and temporary FGD system bypass, in which the liner is exposed to gases of different temperatures in a cyclic manner. For the thermal gradients presumably associated with a unit with configuration 3 (mixing in the stack), however, it is possible that this mechanism is significant. In stacks 400 to 600 ft (120 to 180 m) high, it would take very little nonuniformity in thermal expansion to produce a lean.

Chemical properties also suggest an explanation. A certain amount of absorbent liquor is entrained in the flue gas exiting an FGD system. Even with the mist eliminators operating at design efficiency, some dissolved chemical species will be carried over to the stack liner, where they can penetrate the brick and mortar. This penetration, mainly of sulfates of calcium and magnesium, would not itself be expected to cause a lean—a speculation borne out by the fact that there are no leans reported for units having configuration 4. These compounds might, however, deform or degrade the brick and mortar by expansion due to chemical reaction or hydration as the liner is subjected to cyclic variation in the gas temperature. If the greatest deposition and penetration occur at the part of the liner directly opposite the scrubber outlet duct, as seems reasonable, then a lean due to this mechanism would be in the direction of the breeching. From Table 1, it can be seen that this is the direction of many of the leans.

Other possible contributing factors in leaning pertain to the materials and techniques of construction. Nearly all the leaning stack liners are made of red shale brick, and since Southwest-1 rebuilt its liner with fireclay brick, the lean has not recurred; thus, red shale brick is a candidate for investigation. However, many liners of red shale brick are not leaning. Similarly, the types of potassium silicate mortar commonly used throughout the industry have differences that could cause variable response under certain conditions. This possibility, too, is being investigated.

Can the actual construction techniques play a role in terms of lean potential? For example, does the quantity of mortar surrounding the breeching entrance differ appreciably from that in other areas of the liner? Does the design of configuration-3 stack liners—with breechings atop one another creating two large void areas in the same vertical plane (Figure 1)—have some possible significance? Future EPRI work will attempt to answer such questions.

Continuing efforts

Although the problem of leaning liners may not be major in terms of the number of units affected, it is an important one to resolve for both existing and future units. For existing units, it is important to identify measures to halt or reverse leans before structural problems result. For future units, designs that have shown potential for leaning should be avoided and design features should be incorporated to provide flexibility in absorbing some differential expansion within the liner. EPRI has initiated a program to document the true plumb of various brick liners, considering liners known to be leaning and liners that may have a potential to lean. Among the objectives of this program are (1) to measure several new brick liners to determine their degree of lean before unit startup, (2) to profile leaning liners to determine where the leans are being generated, and (3) to monitor changes in brick liners with time.

A laser surveying technique has been demonstrated to be effective in obtaining liner profiles from inside the liner base. This technique was first demonstrated on a new stack at the Dolet Hills station of Central Louisiana Electric Co. The 450-ft (138-m) liner was found to be out of plumb by less than 2 in (5 cm). Leaning liners at both the Dallman and Marion stations (Table 1) have also been surveyed, and the data are currently being analyzed.

It appears that no one mechanism is causing all the problems. It also seems clear that thermal gradients are involved. Although the precise mechanisms causing the problem have not yet been identified, it would seem prudent to ensure as uniform a temperature profile as possible for the gas stream within the brick liner of the stack. This would dictate that configuration 3 be avoided and that adequate mixing be provided for configuration 2 (and configuration 1 when indirect reheat is used) before the combined gases enter the stack. *Project Manager: Robert Moser*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

TRANSMISSION SUBSTATIONS

Insulation coordination of HVDC converter stations

The engineering studies required to establish a feasible and economic approach to insulation coordination generally constitute a significant portion of the total engineering for HVDC systems because the stakes are high. The cost of insulation and the cost of protective devices required to protect the insulation are substantial. For those points in the system at which insulation is likely to be stressed beyond its capability, surge arresters and/or control strategies must be applied to limit the voltages to acceptable levels.

In RP2323-1, General Electric Co. has developed a methodology for establishing the insulation coordination of an HVDC converter station. The methodology applies fundamental analytic principles and sets forth a step-by-step procedure for both preliminary and final insulation coordination. It also presents modeling and analytic techniques to assist users in performing insulation coordination calculations.

Final coordination uses more detailed design data, and computer simulation studies are often required. The more sophisticated analyses permit cost trade-offs where the cost of insulation withstand is weighed against the cost of various surge arrester configurations. The methodology tends to reduce the overall cost by applying the minimum withstand requirements and uses the lowest number of surge arresters.

Researchers examined forced-air cooling of valve arresters and found the technique to be feasible. An example will be given in the final report to illustrate potential cost benefits that utilities might realize by cooling valve arresters with forced air. The study group also examined the application of zinc oxide arresters for control of ac bus temporary overvoltages and found them to be feasible. Fundamental characteristics of ac bus temporary overvoltages on converter load rejection were reviewed, and the action of zinc oxide arresters in limiting these overvoltages developed. Finally, the group compared component model frequency response characteristics with actual component frequency response data to verify the modeling techniques.

In a follow-on study the consulting firm C. T. Main is developing a more generic perspective of insulation coordination than the view developed by General Electric (RP2323-2). This study, which deals more with the application of metal oxide arresters, is expected to be finished early this year. The combined results of this project will be published as a handbook later in the year.

The resulting design rules will also be reproduced as an interactive tutorial computer program for an IBM–PC. The program will illustrate preliminary insulation coordination and allow users to input specific system data to perform preliminary insulation coordination calculations. *Project Manager: Selwyn Wright*

Arc interruption studies

EPRI has continued its work to develop technology that will permit the design and manufacture of more-reliable and less-expensive interrupters rated 69 kV and above (RP246). Previous work by the contractor, Rensselaer Polytechnic Institute, reported in EL-284, EL-1455, and EL-3293, investigated the electric arc and its interactions with the gas flow in the general geometries found in puffer-type interrupters. The latest accomplishment is the development of a computer program that analyzes cold gas flow in nozzle-type interrupters.

Arc interruption in a puffer-type interrupter occurs in an axial nozzle through which the contacts pass. It is clear that the details of the design of the electrodes, the nozzle, and surroundings are critical to the performance. The latest contract under RP246 concentrated on this key area. A computer model of flow is of interest because high-voltage testing is an expensive route to design, whereas design variations can be considered quickly and inexpensively by computer. The new program allows inputs that readily adjust the geometry, the gas pressure, or the gas type. It can accommodate single or double flow that is symmetrical or asymmetrical. Effects from the presence of the electric arc, especially density changes produced from the intense heat, are not included.

The predictions of the program were verified by experimental checks. Pressure measurements at multiple locations in each of three different full-scale geometries compared favorably with the flow field calculated by the computer.

The program has been completed, and a final report and a user's manual are being prepared. The program and manual are intended to be used by switchgear manufacturers in their future design work. Rensselaer Polytechnic Institute was the contractor. *Project Managers: B. L. Damsky and Glen Bates*

Vacuum arc fault current limiter

Researchers at the State University of New York at Buffalo recently completed an analytic and experimental effort supporting RP564, Westinghouse's development of a fault current limiter that uses vacuum arc fault current commutation. An earlier *EPRI Journal* R&D status report (March 1982, p. 42) describes the principles of operation and application. This project is now complete; final report EL-4187 (Westinghouse) was issued in September 1985, and EL-4186 (SUNYAB) was issued in October 1985. Researchers concluded that although this concept appears feasible for many applications, its complexity and projected cost do not warrant the considerable additional work required to produce a full-scale prototype.

Ongoing work at SUNYAB under RP993-6 is directed toward the search and limited evaluation of other current-limiting concepts, particularly those that do not require the use of arcing devices. A literature survey has been conducted, and investigators are making small-scale analytic and experimental evaluations of promising concepts. Results to date indicate that known current-limiting concepts for high-voltage ac systems may be divided into four broad categories.

▫ Schemes that use mechanically operated high-speed arcing devices to commutate the fault current into a current-limiting impedance. These schemes tend to be complex and costly. They also require considerable development work on the arcing devices, high-speed mechanisms, and sophisticated sensors needed.

▫ Schemes that use tuned circuit concepts to rapidly change impedance at the onset of a fault current. Although some of these schemes appear feasible with existing technology, they tend to be large and costly.

▫ Magnetic devices that rapidly change impedance in response to a fault current. This impedance change can be in response to some mechanical change or a change in a control winding. These devices also tend to be large and costly and can introduce undesirable harmonics. In some instances the limited current after the increase in impedance can be offset more than 100%, which means that subsequent operation of circuit breakers would be affected by the delay of the current zero crossing that is normally required for interruption.

▫ Current-limiting devices that rapidly change state in response to a fault current. One example of such a scheme uses a superconducting element that rapidly increases resistance at the onset of a fault current. This increase in resistance occurs when the superconducting element changes to a normal state in response to the self-magnetic field generated by the fault current. With known technology it appears that this scheme will also be large and costly, especially its refrigeration requirements. Many unanswered questions also remain concerning reset time, reliability, and so on.

Current plans are to report on the studied current-limiting schemes by mid 1986. *Project Manager: Joseph W. Porter*

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Improved RF monitoring techniques

The problem of detecting arcing inside a generator led to the development of a radio frequency (RF) monitor (RP970-2). In-service experience with the monitor confirmed the need to improve its sensitivity and frequency range. With the monitor's present configuration, certain kinds of arcing could persist undetected. To overcome this problem, EPRI initiated the current project to improve the monitor's capability as well as to understand the nature of the various forms of arcing that can occur in a generator (RP2325). The project was also expanded to cover application of the RF monitor to hydroelectric generators.

Project personnel developed an approach in which a monitor senses the RF electric field surrounding the generator neutral lead, as opposed to the former approach of detecting an RF-produced current in the neutral connection to ground. Figure 1 shows the location of the voltage coupler in a typical configuration using the new approach.

Any arcing that occurs in the generator is picked up by the stator winding in much the same way that an antenna receives a signal for a radio circuit. This increased sensitivity presents new challenges; some arcing outside the generator is coupled into the generator stator winding and is detected by the generator RF monitor. Many cases of inadequate shaft grounding have triggered the monitor, giving the false impression that a problem lies somewhere inside the generator.

Investigators developed methods for determining sources of RF energy both inside and outside the generator environment. Being able to determine the source of arcing is crucial for discounting false external indications, as well as for developing a diagnostic tool that can help pinpoint the source of arcing in generators.

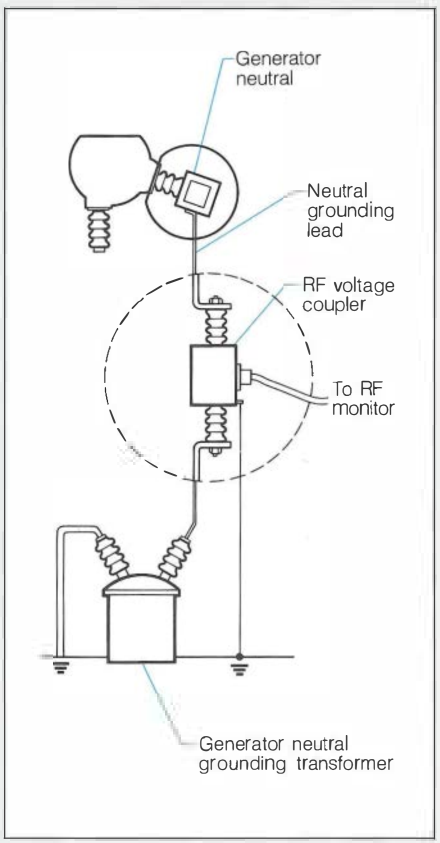


Figure 1 Typical location of the voltage coupler for the improved RF monitor. In this new configuration the RF field surrounding the generator neutral lead is monitored.

The project was completed in December 1985, and Westinghouse Electric Corp. expects to offer the improved RF monitor commercially later this year. *Project Manager: J. S. Edmonds*

Rotor-mounted monitoring system for hydroelectric generators

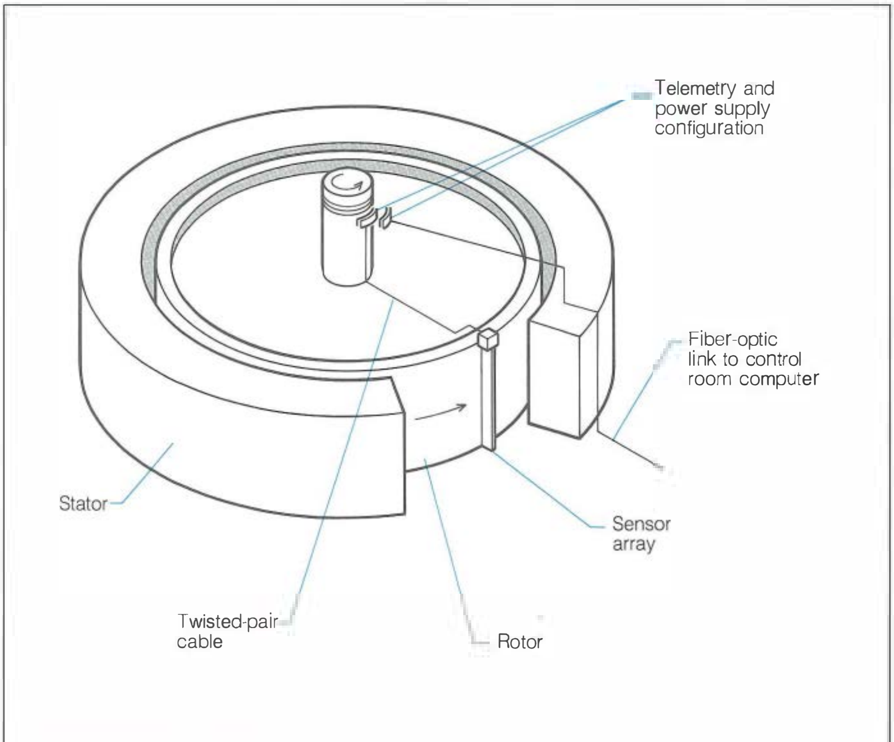
The following conclusion was stated in the report of an earlier project (EM-3435). "The predominant source of outage time (in hydroelectric generators) is caused by stator windings. The old asphalt-mica–insulated windings were generally trouble-free during their lifetime. But modern synthetic resin-mica-glass or synthetic fabric–type insulated windings are often not adequately fitted, embedded, or firmly held in the slots. The consequences are mechanical vibration and electrical corona discharge damage to the windings and to the iron core, sometimes within the first few years."

It is apparent that insulation systems in future hydrogenerators and rewinds will need improvement. It is also apparent, however, that utilities would benefit from improved monitoring techniques that would enable them to anticipate a developing problem and locate it with precision. Then they could make temporary repairs or modifications before a catastrophic failure occurred. Temporary repairs allow utilities to decide an optimal time to shut a unit down for permanent repair or winding replacement and possibly minimize total downtime.

What is needed is a relatively simple, effective, and inexpensive device for monitoring the stator from the vantage point of the rotor, one that would sweep over the entire stator on a continuous basis once each revolution. Conceptually, such a device would appear as shown in Figure 2. Parameters to be measured could include any that would adequately signal a developing distress in the winding, such as temperature, partial discharge radiation, or other high-frequency electromagnetic or acoustic radiation. Such a monitoring system should be capable of locating, to the coil or slot, the source of the distress signal.

In this EPRI project investigators concluded that a rotor-mounted scanner would be technically feasible and economically viable for commercial use (RP2591-2). The U.S. Bureau of Reclamation has installed a version that has operated for two years, thereby providing proof of principle.

Figure 2 Rotor-mounted scanner. This concept holds promise for the development of a relatively simple, effective, and inexpensive monitor for stator windings in hydroelectric generators.



In addition to infrared, several promising sensor types will be investigated in a follow-on project to develop the rotor-mounted scanner. Specifically, sensor types slated for inclusion are (1) RFI ferrite antennas mounted on the edges of the rotor rim to scan for arcing in distressed stator coils; (2) a novel device for detecting transverse vibrations of loose coils; and (3) a way to measure the dynamic air gap.

The rotor-mounted scanner requires no critical components other than sensors, and there are numerous manufacturers of requisite sensor types. However, none of the potential suppliers has direct experience with sensors operating at a steady-state centrifugal load of 100–300 g forces. Therefore, project personnel have concluded that in-generator components, such as sensors and sensor electronics, must undergo design verification testing on a test bed designed to simulate g forces, temperatures, electric and magnetic fields, and RFI that might reasonably be expected in the worst of hydrogenerator environments. The project team further concluded that it is possible to develop a universal design for a commercial rotor-mounted scanner, thereby alleviating the problem of custom designing for varying generator configurations.

Preliminary work in a follow-on project involves rigorous testing of various components at elevated temperatures and under high continuous loads (RP2591-5). During this portion of the project, different sensor types will be tested to determine which exhibit the best combination of durability and sensitivity. After the equipment has been thoroughly tested, the stationary controller will be designed, assembled, and tested for use with the system. The scanner will undergo extensive factory test as an integrated system before it is installed on an in-service hydrogenerator for long-term performance and reliability tests. The project is scheduled for completion early in 1987. *Project Manager: J. S. Edmonds*

OVERHEAD TRANSMISSION

Transmission line foundation analysis and design

Over the years, numerous models have been proposed for analysis of foundations commonly employed for transmission line structures. The majority of these models were developed, and in some cases tested, for specific foundation geometries and soil conditions. The limitation of these models is that they are not accurate for use outside original control conditions, usually because they do not address all the controlling soil variables adequately and, as a result, are incomplete. The major contribution of a current research project at Cornell University was development of a unified model for the static analysis of a wide range of foundations (RP1493). The model is based on a cylindrical or rectangular shear mechanism and is flexible enough to accommodate the compression and uplift modes of loading, including the cone breakout and punching mechanisms sometimes observed in uplift.

Since the initial report (EL-2870) was issued, the unified model has been further refined, and the results of this research have been incorporated into a computer program called CUFAD (compression uplift foundation analysis and design). The program can be used on a personal computer, making it highly accessible to engineers who are appraising alternatives during the foundation design process. CUFAD is designed to become an integral part of the TLWorkstation software.

To help transfer these research results into engineering practice, two foundation design seminars will be presented in July 1986. Hands-on experience with CUFAD will be a prominent feature of the seminars. Also featured will be the computer program MFAD (moment foundation analysis and design), which is a revision of the PADLL program written by GAI Consultants (RP1280). In addition to being easier to use, MFAD provides for analysis of both direct embedment and drilled-shaft foundations for high overturning moment applications. The new name implies a broader use to both foundation types; it is not necessarily restricted to drilled shafts, as was PADLL. Details of the seminar will be announced in the spring. *Project Manager: Vito J. Longo*

DISTRIBUTION

Laser detection of voids and contaminants in cable insulation

This research project has as its goal the development of a far-infrared laser (FIRL) instrument capable of detecting imperfections (voids or contaminants) in distribution cable insulation. The instrument is designed to locate imperfections as small as 2 mils while the cable insulation is being extruded at speeds up to 80 ft/min (0.41 m/s). Currently this project has three phases.

□ RP794-4 with United Technologies Research Center (UTRC) to design and construct a FIRL instrument capable of on-line inspection of cable in a factory environment. This work has been completed, and the instrument was shipped to Essex Cable Co. in Lafayette, Indiana, in mid 1984. Figure 3 shows the instrument installed at Essex.

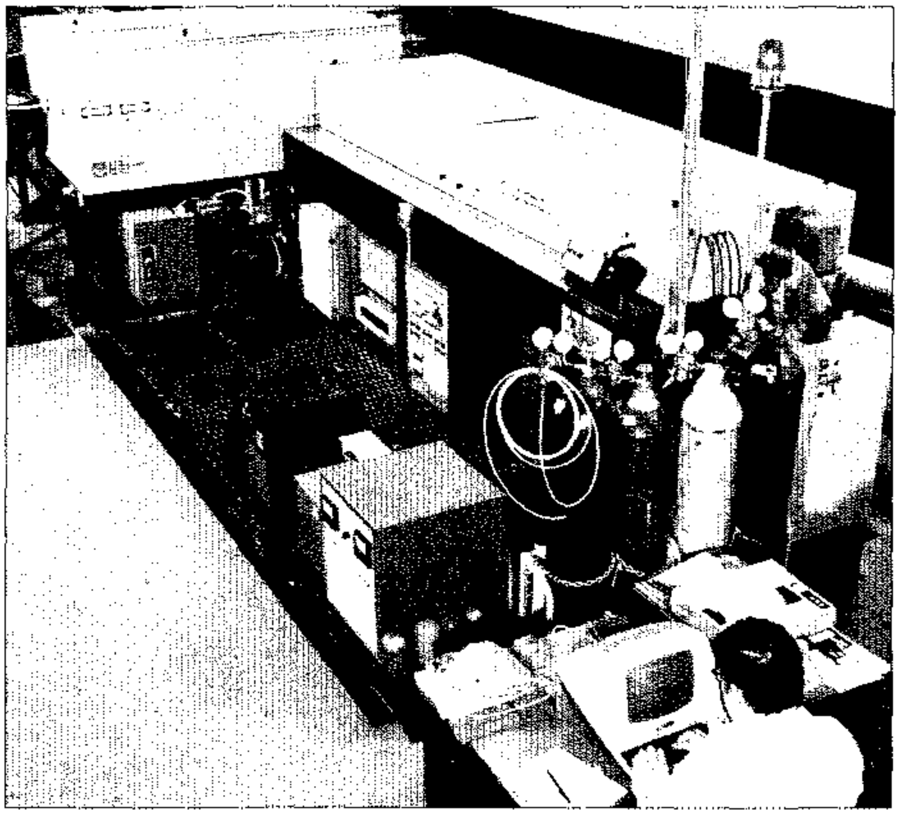
▫ RP794-5 with Essex to install the FIRL instrument and evaluate its performance on cable samples into which imperfections had been purposely introduced and also on sample lots of production cable produced at Essex.

▫ Training of Essex personnel in the operation of the device. This training uncovered some bugs in the instrument, which were corrected.

When the device became operational, sample cables were run to determine its performance. Although the FIRL worked as expected, deficiencies were uncovered in two areas. Cross-linking by-products and moisture in freshly extruded cable could materially change the calibration of the instrument. Researchers also learned that better software to resolve and present the data was needed to avoid laborious manual interpretation. These two deficiencies are now being addressed, and they should be corrected early in 1986.

In another project with UTRC, researchers will determine the feasibility of using the FIRL instrument to inspect triple-extruded cable (RP794-6). Although this work is not fully complete, results to date indicate that if the present FIRL instrument is used to inspect triple-extruded cable containing modified mixtures of currently used semiconducting material, its sensitivity would be reduced by a factor of 4 or 5. This means that the smallest imperfection that could be detected would be in the range of 8–10 mils. However, the direct laser detection scheme currently used could be changed to a heterodyne detection scheme to increase its sensitivity. This method can reduce the noise in a detection system and thus greatly increase its sensitivity to very low power radiation. Heterodyne detection makes use of the interference phenomenon of two coherent radiations, such as two stable laser beams, instead of the one beam currently employed in the direct-detection scheme. The development of such a scheme is currently under way at UTRC for another and totally different application. Although this scheme appears feasible for inspecting triple-extruded cable with good sensitivities, it introduces additional complexity and has stringent operational requirements for optimum performance. Finally, there is some possibility of changing the materials now used in the semiconducting shield. This change would allow the present instrument to be used with triple-extruded cable, provided these new materials are used as the insulation shield. Work to ascertain whether appropriate shield materials can be developed that will be acceptable to both utilities and manufacturers is continuing. *Project Manager: Joseph W. Porter*

Figure 3 This newly developed far-infrared laser instrument for inspecting distribution cable insulation is being tested at the Essex Cable Co.



R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

CLOUD CHEMISTRY AND PHYSICS RESEARCH

The relationship between emissions into the atmosphere and acidic deposition has been of growing public concern, and pressure has increased on Congress and regulatory agencies to control emissions, principally from industrial sources. It is important to the electric power industry that any emission control strategy be based on well-conducted scientific studies. We now know that complex chemical and physical processes in clouds play an important role in the transformation of emissions. These processes influence where and in what form emissions come down in precipitation. In fact, what happens in clouds bears directly on the relationship between reductions in sulfur dioxide (SO_2) emissions and the occurrence of sulfate in precipitation. Therefore, cloud processes must be considered in the theoretical models that may form the basis of regulatory assessments.

Several routes are available for gases and particles in the atmosphere to enter the water that makes up clouds. Substances may be incorporated when water vapor condenses or after they are sucked into an existing cloud. Some particles become part of cloud drops when water condenses on them, and others are scavenged by falling cloud drops. Gases, like SO_2, are absorbed by cloud drops and then undergo rapid chemical changes by reaction with other substances also being absorbed from the atmosphere, such as ozone (O_3), hydrogen peroxide (H_2O_2), and traces of catalysts, such as manganese and iron.

If gases do not react irreversibly in the cloud drops, they are returned to the atmosphere when the drops evaporate. However, dissolved gases may react with dissolved particles inside the drops, resulting in changed particles when the water evaporates. Most of the drops eventually evaporate, leaving behind an aerosol. And most go through several cycles of evaporation and condensation before some grow large enough to fall out as rain. Because clouds are associated with a great deal of air movement, the spatial distribution of the residues left in the atmosphere will be quite different from that expected from simple trajectory observations.

In summary, clouds are involved in both spatially redistributing substances in the atmosphere and removing substances from the atmosphere. The chemical composition of precipitation, which is generally somewhat acidic all over the world, is the net result of these complex processes occurring inside clouds.

Given the importance of clouds in affecting both air quality (e.g., visibility) and the quality of precipitation (e.g., its acidity), studies of clouds are needed in order to estimate how changes in man-made emissions would alter these characteristics. Thus, EPRI is sponsoring research with the following objectives.

- To develop measurement methods for making observations both in the laboratory and in the atmosphere
- To identify, through laboratory studies, the factors that govern the nature and rates of transformations of sulfur and nitrogen oxides inside clouds
- To survey the simultaneous chemical, physical, and dynamic features of clouds

Methods development

Although clouds contain many drops of water, they are mostly air. To study clouds, it is essential to separate the liquid water from the gases and particles (the interstitial aerosol). Two initial projects supported by EPRI resulted in the development of new sampling devices. One, for use on aircraft, was developed at the Central Electricity Research Laboratories (CERL) of the United Kingdom (RP1311). It is particularly well suited for recovering the interstitial aerosol and has been widely applied in subsequent EPRI-supported studies in the United States under RP2023-1 (Figure 1). Another sampling device, for use in laboratory studies, was developed at the Desert Research Institute of the University of Nevada. It has proved especially useful for accurately sampling cloud water and recovering it for subsequent chemical analysis (RP1434).

As recently as six years ago, most scientists thought that the transformation of SO_2 in atmospheric liquid water was unimportant because its solubility was self-limited by the increase in acidity upon its absorption. Then laboratory studies in England demonstrated that H_2O_2 dissolved in the water could lead to a rapid transfer of SO_2 and conversion to sulfate in cloud drops, limited only by the availability of SO_2 or H_2O_2. As a result of this discovery, it became necessary to measure how much H_2O_2 actually exists in the atmosphere and in cloud water. Because no satisfactory method existed for this purpose, EPRI sponsored work at the National Center for Atmospheric Research (NCAR) to develop one (RP2023-4). The resulting measurement technology has now been used extensively in EPRI-sponsored surveys by NCAR and the Brookhaven National Laboratory and has been transferred to several other researchers in the United States, Canada, and Europe. In addition to this field-worthy chemical method, EPRI is sponsoring the development of a laser spectrometer at Unisearch, Ltd., in Canada (RP2023-5). It will serve as a reference standard for measuring gas-phase atmospheric H_2O_2.

Other new instrumental methods apply initially and primarily to laboratory studies. These include several developed under RP1434: a laser transmissometer for real-time measurements of cloud water content; a three-stage parallel-plate diffusion chamber for relating drop size and aerosol solute content to critical water vapor supersaturations; a miniature probe for continuous monitoring of cloud water pH; and a slide impactor for visually examining individual cloud drop impressions and for measuring the size distribution and concentration of drops.

Figure 1 Cloud sampling devices on board an aircraft (Brookhaven National Laboratory). On the outer and inner sides of the fuselage, cloud water is sampled and separated from the interstitial aerosol with the CERL device; the aerosol is sampled and analyzed inside the cabin. Cloud water is collected through the top of the fuselage on slotted Teflon rods (developed at the State University of New York at Albany) and is saved for laboratory analysis.

A newly developed generator and monitor of free-radical reactions in water is based on flashes of laser light (RP2023-6). Its initial application, at the Georgia Institute of Technology, is to identify NO_x chemistry pathways that are theoretically important in clouds at night. Its next use will be to determine if, like H_2O_2, free radicals are important oxidizers of SO_2 in atmospheric liquid water, as theory suggests.

A number of instruments for the airborne observation of clouds were developed or modified at the Brookhaven National Laboratory (RP2023-1). These include a cell for continual cloud water pH and conductivity measurements; a high-sensitivity chemiluminescence analyzer for nitric oxide, nitrogen dioxide (NO_2), and nitric acid; a flame-photometric gas analyzer for continually measuring both SO_2 and sulfate particles; and a fluorescent procedure for continual ammonia measurement.

With cofunding from the Environmental Protection Agency, a method for simultaneously measuring SO_2, formaldehyde, and SO_2-aldehyde complexes in both gas and liquid water phases has been developed at Texas Tech University (RP1630-28). This method is intended to determine under what atmospheric circumstances SO_2 oxidation by H_2O_2 may be inhibited by formaldehyde.

Finally, NCAR has developed an automated method for the continual analysis of SO_2 in cloud and precipitated water (RP1630-12).

Laboratory studies

This new armamentarium of methods is now being applied in both laboratory and field studies of reactions that are involved in clouds. The advantage of laboratory research is the ability to obtain repeatable conditions; however, it cannot simulate the dynamics of clouds in the atmosphere.

As part of an early EPRI project, the Desert Research Institute developed a cloud chamber for studying chemical reactions during the initial period of cloud drop formation (RP1434). In this facility the chemistry of cloud water was studied as a function of various reagents (such as SO_2, NO_2, and several kinds of condensation nuclei) added to the air before the cloud was formed. This research produced several findings.

- The oxidation of SO_2 in clouds is very slow unless other reagents are present.

- When O_3 is present, the SO_2 oxidation rate diminishes as cloud water pH goes down; in any case, the rate increases in proportion to the amount of O_3 present. However, if the SO_2 concentration is increased, the rate of conversion to sulfate goes down. This indicates the importance of oxidizing substances present in air in determining how much SO_2 ends up as sulfate and contributes to precipitation acidity.

- When sea-salt-like particles (i.e., chlorides) are added, the conversion rate of SO_2 increases. This indicates that chlorides from industrial emissions or in marine air could catalyze the formation of sulfate in cloud water.

- When manganese salt particles are added, the rate of SO_2 conversion to sulfate increases dramatically. Whether or not this finding realistically applies to the atmosphere is the subject of a study being conducted by Aerospace Corp. at much lower concentrations (RP2023-7). For the first time, manganese and iron catalytic reactions of SO_2 in water are being studied at concentrations found in the atmosphere. Under these conditions the oxidation rate seems to be dependent on both pH and SO_2 concentration.

- When NO_2 is added to the cloud chamber together with SO_2 and the cloud water is acidic, the SO_2 oxidation rate is not much greater than when no NO_2 is present. This is consistent with laboratory results obtained at Brookhaven (RP2023-1). But when the cloud water is less acidic (pH>6), SO_2 oxidation seems to be very much enhanced by NO_2. The relevance of this finding to realistic atmospheric conditions remains to be determined.

With the new methods developed at Texas Tech University (RP1630-28) and at NCAR (RP1630-12), laboratory studies of SO_2 oxidation in the presence of formaldehyde, which could be an inhibitor, have been conducted for the first time at atmospherically realistic concentrations. The studies found that the inhibition of oxidation by formaldehyde is pH dependent, and that in the typical pH range (<5) of cloud water over the eastern United States, formaldehyde is not an inhibitor. This knowledge has already led to changes in air quality models.

Often the water in clouds is frozen; this is the case at higher altitudes during all seasons and at all altitudes during winter in northerly regions. We know little about chemical processes in such clouds, and theoretical models tend to ignore them. EPRI therefore is sponsoring a laboratory study at a novel facility at the University of Toronto to explore the transfer of substances like SO_2, hydrochloric acid, and nitric acid between the gas and frozen water phases (RP1630-48).

Another lack of key information concerns the efficiency with which gas molecules in air attach themselves to droplet surfaces. Theoretical models now assume values (sticking coefficients) that have large uncertainties. To eliminate this weakness, EPRI is cosponsoring work at Boston College and Aerodyne Research, where a novel apparatus and method have recently been invented (RP2023-8).

Observations in clouds

After CERL developed its cloud water and interstitial aerosol separator for use on aircraft, the first observational study of clouds supported by EPRI involved tracking the plumes of coal-fired power plants from England over the North Sea. Tracers released from the power plants were used to establish plume locations; the aim was to follow the fate of sulfur and nitrogen oxides as they interacted with clouds. This research showed that industrial emissions do influence cloud water composition, that cloud droplets absorb pollutants from the ambient air, and that concentrations in cloud water are typically 5 to 10 times higher than in precipitation. The most important results were a better understanding of how to use tracers and the demonstration of the sampler, which has since proved so useful.

A second observational study was aimed at understanding the transfer of sulfur and nitrogen oxides and their oxyacids from ambient air to cloud water (RP2023-1). This extensive project, conducted by Brookhaven, has served as the basis for much of EPRI's continuing work in cloud chemistry and physics. The design of the observational study was based on expectations arising from existing theory and laboratory findings. Many flights were conducted—primarily in nonprecipitating stratiform clouds—in remote and urban areas of the southern United States during fall and winter, in the northeastern United States during summer and fall, and in southeastern Canada during winter. Much of the work was done in cooperation with the Canadian Atmospheric Environmental Service. The observations by Brookhaven have been supplemented during the last year by aircraft flights conducted by NCAR over the eastern United States, Sweden, and Italy (RP2023-4). A number of important results have come from this observational research.

- Although SO_2 and O_3 coexisted, SO_2 and H_2O_2 did not coexist in clouds in these studies. In other studies, over Los Angeles, they have been found to coexist; the oxidation inhibition occurring there is related to the presence of formaldehyde. In clouds, SO_2 and H_2O_2 will react in the liquid phase to yield sulfate. Obviously, such a reaction is either SO_2 or H_2O_2 limited. When SO_2 occurs in the interstitial vapor phase, the oxidation to sulfate in cloud water appears to be H_2O_2 limited.

- Questions have been raised about the origin of H_2O_2 in cloud water. In current air quality models, H_2O_2 sources are theoretically accounted for by gas-phase photochemically initiated reactions. Laboratory research at the Georgia Institute of Technology will establish the potential role of oxidants possibly being generated in the water directly (RP2023-6). Flights by NCAR measuring H_2O_2 in ambient air and cloud water simultaneously are attempting to evaluate the theories. Generally, H_2O_2 concentrations are higher in summer than in winter, at the more southerly latitudes, and over regions with lower SO_2 emissions.

- SO_2, NO_2, and O_3 commonly occur as interstitial gases in clouds, consistent with their low solubilities. In contrast, nitric acid and ammonia, because of their high solubilities, are removed from the interstitial gas phase and are found mainly in cloud water.

The overall significance of the Brookhaven and NCAR work is the realization that nonlinear processes may be important in the conversion of atmospheric SO_2 to sulfates. The breakdown of a simple proportionality between SO_2 emissions and sulfates in precipitation has profound implications for defining source-receptor relations. Furthermore, these observational studies have confirmed the conjecture, based on laboratory studies in England six years ago, that the conversion of SO_2 in acidic cloud water is dependent on the availability of H_2O_2. The origins of H_2O_2 in cloud water and the role of other potential oxidizers in the atmosphere remain to be established. Nevertheless, as a result of worldwide research, we now know that significant reductions of sulfate and acidity in precipitation will follow from a decrease in SO_2 emissions only when and where there is no deficiency of oxidants in the atmosphere.

In conclusion, EPRI's cloud chemistry research is well under way and continues to focus on reactions leading to the incorporation of atmospheric components into cloud water. This work is demonstrating to what extent oxidants and metal catalysts control the conversion of SO_2 and nitrogen oxides to products that could increase the acidity of precipitation. The recently added emphasis on cloud physics will involve research on microphysical topics, circulation and entrainment by clouds, and dynamic cloud modeling. EPRI's studies have been creating a new understanding of how the cloud component should be represented in regional air quality models. *Project Managers: Peter K. Mueller and D. Alan Hansen*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

DSM INFORMATION DIRECTORY

Demand-side management (DSM) is the planning and implementation of utility activities designed to influence customer use of electricity in ways that will produce a wide variety of benefits to both the utility and its customers. Utility DSM programs include load management, the promotion of new uses, strategic conservation, customer generation, and rate innovation. DSM programs can be classified according to the load shape modification objective associated with each program: peak clipping, valley filling, load shifting, strategic conservation, load growth, and flexible load shape. Although a utility's specific load shape objectives are determined to a great extent by its reserve margin, load profile, load growth, and other operating characteristics, one common thread ties together all demand-side activities—they provide increased flexibility with which to pursue strategic objectives. In response to the increased importance of demand-side activities in utility planning and operations, EPRI initiated a project in 1984 to integrate, generalize, and expand DSM tools, data, and experiences. The DSM Information Directory, *the first major output of that project, is a catalog of information sources useful in planning DSM programs (EM-4326).*

Very little of the large body of data related to DSM has been effectively organized and shared within the industry. As a first step toward better utilization of existing information, the *DSM Information Directory* has been developed to review the available information sources and to identify the sources useful in meeting the specific information requirements of almost any utility undertaking DSM activities. The directory is organized in three parts: identification of information needs, identification of information sources, and linking of sources and needs.

The execution of a demand-side strategy entails nine separate steps. These steps can be used to categorize the information that utilities commonly require in conducting DSM.

- Objectives: establishment of broad strategic objectives (e.g., to improve customer relations, to increase financial performance), quantification of those strategic objectives, and translation of those goals into desired load shape changes
- Alternatives: identification of the demand-side alternatives that can be used to accomplish the targeted load shape change
- Customer acceptance: estimation of the number of customers who will participate in the program on the basis of the expected marketing effort
- Customer response: estimation of the effect per customer
- Load shape effect: estimation of the diversified class and system load shape effects of each alternative, accounting for any interaction effects
- Transmission and distribution effects: identification of the effects that potential DSM programs could have on transmission and distribution systems
- Cost/benefit analysis: translation of specific costs and benefits into an overall evaluation of the attractiveness of a particular demand-side initiative
- Implementation: establishment of the logistics for executing a specific demand-side strategy
- Monitoring: comparison of program effects with the objectives established in the first step

Utilities have two sources of information—primary sources (sources within a utility's own organization) and secondary sources (other utilities or the industry as a whole). The directory is limited to secondary information sources, which fall into five basic categories.

- Utility contacts (networking): formal and informal contacts with utilities with similar planning needs or programs
- Planning models: software packages that not only help analyze specific DSM issues but also provide useful insights into methodology and default data
- Metering studies: large, systematic efforts to monitor customer energy use to establish end-use patterns or DSM program effects
- Utility surveys: utility-sponsored market research to better understand customer behavior and preferences
- Other sources: reports, handbooks, reviews, methods, and demonstration project results related to DSM

The directory provides the link between information sources and information needs through a series of summary matrixes that cross-reference specific sources with individual information requirements. For example, a matrix on residential DSM technologies lists sources of information on performance characteristics, installed cost, and the like under the categories of insulation, passive solar, and so on.

The remainder of this report reviews the range of information available in each of the five basic categories of information source.

One way that utilities can acquire information is by aggressively seeking out other utilities that have successfully applied DSM. Establishing a network of contacts within the industry can provide an invaluable resource of shared experience. General program results, effectiveness of promotions, and planning pitfalls are just a few examples of the insights that can be obtained through direct contact with individual utilities.

The extent of DSM activities is evidenced by the number of utility programs for the various customer classes. The directory lists residential, commercial, and industrial programs by program type and provides additional information about each program—the name and telephone number of the appropriate utility contact, for example.

As in the case of supply planning, in DSM formal planning models can be quite useful in several ways. Use of models can allow a utility to analyze alternative DSM strategies, to optimize the design of DSM programs, and to compare DSM programs with supply-side alternatives. Formal models have the capability of analyzing a problem relatively quickly. Studies can be performed to test the sensitivity of the results to changes in input values. It is the ability to perform consistent, repetitive analyses that gives value to formal computer models.

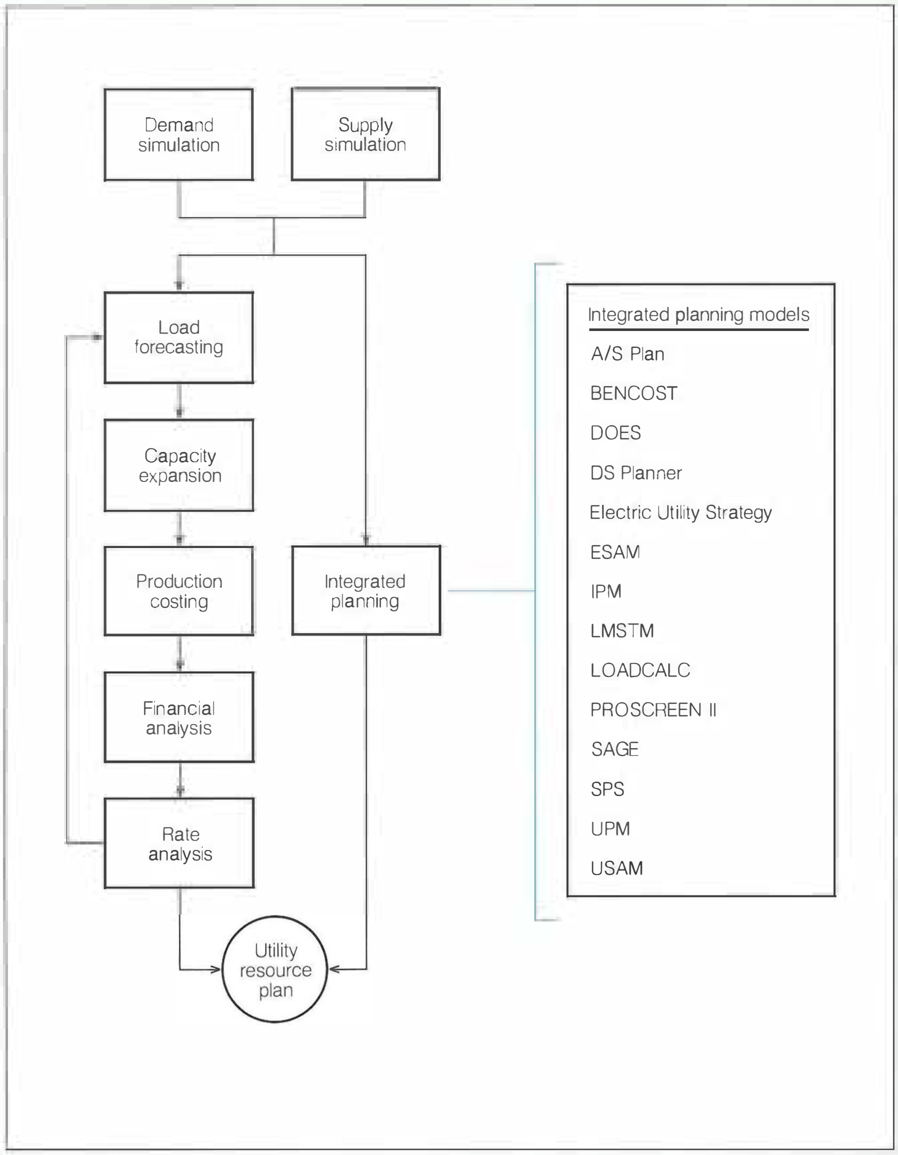
The methodology incorporated in a model is itself a valuable input to a DSM analysis. Development of such a methodology includes identifying important variables, structuring the variables into cause-effect relationships, and quantificating those relationships. Such insights can themselves provide a significant shortcut to a utility seeking to develop a model customized to its specific needs and situation.

Models can often be used as a source of default data. In many cases a utility may not have certain types of data specific to its service area. Frequently model packages contain data sets that provide an adequate alternative to the collection of data specific to the service area.

The modeling section in the directory contains descriptions of 80 computer models that are potentially useful for planning and evaluating DSM programs. Only formal models, complete with computer software, are presented. An attempt was made to develop a complete list rather than select only those models designed specifically with DSM in mind. The appropriateness of each model depends not only on its particular design features but also on such factors as cost, availability of support, and computer requirements, as well as on the unique needs and characteristics of each individual user. To provide a useful classification, each of the models has been categorized according to its primary function (Figure 1). The directory also includes a summary of each model that states the model's primary uses, its relationship to other models, its approximate cost, its computer requirements, and so on.

An essential input to the planning and evaluation of DSM programs is metered load data. Because the collection, processing, and analysis of load data are time-consuming and expensive tasks, it is not feasible for a utility to engage in metering programs for all DSM alternatives that may be of interest. To obtain timely and cost-effective load shape data, utilities can rely on other means, such as borrowing load shape information from other utilities or estimating data by using simulation or other analytic techniques. Regardless of which method is selected, metered load data are essential, particularly at the end-use level.

Figure 1 The *DSM Information Directory* presents detailed information on 80 computer models useful for utilities in planning and evaluating demand-side management programs. The models are categorized according to the major functions shown here—for example, the directory covers 14 integrated planning models.



Over 150 metering programs conducted by approximately 50 utilities are summarized in the directory. The information presented is adapted from *Feasibility Study: Load Data Pool* (EPRI EA-3683). Each metering study is characterized according to the format depicted in Figure 2. In addition, summary tables are provided to organize the metering studies by customer class, utility, and end use.

Utilities frequently survey their customers to obtain information unavailable from such sources as billing records or metering studies. Surveys can provide data on consumer behavior, socioeconomic characteristics, attitudes, and buying intentions and can help estimate market potential, forecast sales patterns, or analyze customer preferences.

Although every utility that sponsors surveys has unique circumstances, objectives, and customer characteristics, the use of one utility's surveys and survey results by other util-

Figure 2 Sample summary of a utility metering study from the *DSM Information Directory*. Over 150 such studies are covered, as well as several other kinds of information sources for use in developing demand-side management programs.

MS #48

Single-Family Air Conditioning, Space and Water Heating Loads: Test of Bidirectional Power Line Carrier

Source: Florida Power & Light

Observation interval: 15 minutes

Time period: 24 months ending April 1, 1981

Geographic area: Boca Raton, Florida

Weather station climate: Indoor and outdoor temperature data recorded at homes

Collection/development method: Magnetic tape

Sample plan/method: Selected from 605 volunteers, based on average kWh use, interview, and home survey

Sample size: 125 test homes, 81 control homes

Supplemental information: Demographic, income, housing characteristics, water heater, air conditioning, and heating equipment data surveyed

Limitations: Temperature data not recorded continually, especially during control periods, because of load program limitations

Comments: Main objectives were to test bidirectional power line carrier system hardware, determine the impacts of load control on energy use, and evaluate customer acceptance of appliance control. Available on request. Cost only if edited data required. Data form: computer tape.

ities can reduce for them the burden and expense of DSM analysis. Utilities can review the results of surveys from utilities with similar DSM programs to obtain ballpark approximations of acceptance and response ranges. The information from other surveys can be useful for a utility's own survey by illustrating methodological techniques (that is, such information can demonstrate effective and ineffective questions). Surveys from other utilities also can serve to validate a company's own survey results. The directory includes summaries of 100 utility-sponsored consumer surveys.

Before another utility's surveys can be used to evaluate DSM alternatives, the surveys must be carefully evaluated for accuracy, age, freedom from bias, and so on. Users of the surveys should recognize both their specific limitations (those related to methodology) and their generic limitations (those related to the uncertainty of acceptance and participation levels).

The directory catalogs nearly 1000 summaries adapted from studies, handbooks, and reviews that provide a wealth of information related to DSM. These studies represent research conducted by individual utilities and by electric power research organizations and trade associations. The directory includes several cross-reference matrixes that organize the study summaries into various information categories.

The *DSM Information Directory* provides a summary of required data inputs for DSM analyses and a comprehensive listing of sources of pertinent information. The directory is an important step toward increased use and sharing of DSM information generated by the industry and represents the first major output associated with EPRI's project to integrate, generalize, and expand DSM tools, data, and experiences. *Project Managers: Ahmad Faruqui and William Smith*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

AUTOMATING THE WELD REPAIR OF NUCLEAR VESSELS

As time passes, nuclear pressure vessels may need weld repairs, owing either to a radiation-induced loss of fracture toughness in the steel (which reduces the permissible flaw size) or to the growth of fatigue cracks during service. If defects exceed the acceptance standards set by Section XI of the ASME Boiler and Pressure Vessel Code, the owner utility cannot continue to operate the plant unless workers replace the component or repair the flaw. Although the code accepts the half-bead technique for making such repairs, this technique demands near perfect welding, which is not easy to achieve in a radioactive environment. Looking for an alternative means of repair, EPRI developed a method that combines end milling, to excavate the crack zone, with gas-tungsten arc (GTA) welding, to fill the cavity (RP1236-1). Because both processes can be automated, operators working in protected areas can control equipment in radiation-heavy zones.

EPRI chose GTA welding because the process allows excellent control of weld parameters, provides high-quality deposits, and allows operators to control weld settings easily from a distance. By adjusting weld parameters, heat inputs are controlled so that each layer refines and tempers the heat-affected zones (HAZs) of previous layers. This technique eliminates the step of grinding the first layer, which is required in half-bead repair.

The test steel for the project was ASME SA508 Class 2, a vacuum-treated, quenched-and-tempered alloy typical of steels used in nuclear pressure vessels. First, the researchers established the GTA-welding parameters needed to achieve 100% grain refinement in the flat position, examining the effects of heat input as a function of voltage, current, travel speed, wire feed speed, preheating, and bead positioning (offset and overlap). Then, after comparing the HAZ hardness of welds made by GTA and half-bead procedures, they modified the flat-position GTA-welding parameters for use on an inclined plane, the condition encountered in field repair.

To prove the GTA refinement-tempering procedure, the researchers made a multilayer weld on a 45° plane. Examining the HAZ microscopically, they found complete refinement with three weld layers. In the HAZ, peak Knoop hardness (approximately equivalent to Brinell and Vickers hardnesses) ran about 370 after three layers and 340 after six. Additional beads tempered the deposit further: a 10-layer weld peaked at 320. (Figure 1 shows a test mock-up.)

Half-bead repair calls for considerably more effort and manpower than the milling–GTA welding method. The half-bead technique requires preheating (to 350°F; 177°C), gouging by the air-carbon arc process, and grinding. The EPRI procedure calls for milling, without preheating or grinding, to gouge the cavity. Both procedures specify magnetic-particle testing (MT) to ensure that no crack traces remain.

Figure 1 This nozzle mock-up was used in testing a new weld repair method developed by EPRI. The method, which features gas-tungsten arc welding, can be easily automated for use in radioactive environments.

For purposes of comparison, the researchers ran the half-bead technique, following the steps required by Section XI of the ASME Boiler and Pressure Vessel Code. They deposited the first layer with 3/32-in-diam E8015-C3 electrodes, MT-inspected the layer for cracks, ground a series of grooves to one-half the depth of the deposit, ground the first layer to remove one-half its thickness, verified the removal depth, and MT-inspected the layer again. They then deposited the second and subsequent layers with a 1/8-in-diam electrode, reinspecting by MT after each deposit. To complete the job, they raised the temperature to 450–550°F (232–288°C) for a minimum of two hours, cooled the repair, and ground the surface for nondestructive evaluation.

Clearly, the half-bead technique, which calls for stick-electrode welding, requires considerable manpower—for gouging the cavity, welding, and examination. Milling and GTA welding, required by the new repair procedure, can readily be automated for remote control from safe areas.

To determine the mechanical properties of the weld metal and the HAZ produced by the new procedure, the researchers ran tension tests, Charpy V-notch impact tests (at −150 to 550°F; −101 to 288°C), drop-weight tests, and fracture toughness tests. Fracture and tension tests were run at different temperatures to evaluate the upper-shelf, transition, and lower-shelf regions.

The tension tests proved the weld metal to be strong (yield strength of 82,000 psi, or 565 MPa; tensile strength of 94,000 psi, or 648 MPa) and ductile (31% elongation, 77% reduction in area). Toughness was also good, as demonstrated by the Charpy V-notch tests: −87 ft-lb at −100°F (−118 J, −73°C) to 210 ft-lb at 550°F (285 J, 288°C). Upper-shelf impact energies ran above 200 ft-lb (271 J), and the nil-ductility transition temperature was −90°F (−68°C). Fracture toughness was high (200 ksi $\sqrt{in}$; 182 MPa $\sqrt{m}$) and showed little drop with temperature in the upper-shelf region.

Since the completion of the experimental activities to develop and characterize the GTA refinement-tempering weld repair procedure, efforts have been aimed at obtaining ASME Code approval. Working with the ASME Section XI subcommittee, EPRI has prepared a code case to allow the GTA-welding process to be used as part of a weld repair procedure.

The approach in preparing the code case has not been to require the specific weld procedure developed in the experimental program; instead, each user utility will be allowed to establish its own GTA-welding procedure as long as it meets the criteria of the code case. With this approach the user has a fair degree of flexibility in establishing the optimal weld procedure for the specific application.

The code case was approved by the Section XI Main Committee at its November 1985 meeting. *Project Manager: D. M. Norris*

ON-LINE CORROSION CRACKING MONITOR DEVELOPMENT

A long-term research emphasis on corrosion cracking of nuclear materials has necessitated the development of sensitive techniques for measuring crack growth in high-temperature water environments. One crack-following procedure that has been used extensively in the laboratory is also being applied in operating plants. By monitoring instrumented cracks that have been introduced directly into the reactor environment, operators can determine, for example, the effectiveness of water chemistry controls in suppressing stress corrosion cracking. Known cracks in plant components, such as stress corrosion cracks in piping welds, can also be instrumented and monitored. A future goal is to enable plant operators to interact with a damage monitoring, prediction, and display system. Such operator surveillance could result in extended component life and reduced maintenance costs.

Many variations of techniques that measure electrical potential have been used to measure crack growth, both in the laboratory and in field applications. The common feature of these techniques is an array of electrical probes in the vicinity of the crack that sense small voltage changes resulting from distortion of a potential field by the crack. Researchers have developed both alternating current and direct current systems, each of which has advantages peculiar to different applications.

A reversing dc potential monitoring technique, developed at General Electric Co., was applied as early as 1978 to measure the growth rate of cracks in carbon steel in the laboratory (RP1248). Later in RP2006-3 researchers adapted the method to the study of surface cracks (semielliptical in shape) in laboratory test specimens. A calibration model converts voltage differentials between various pairs of surface-mounted probes to an estimate of the size and shape of the surface crack. Good crack-size estimates for cracks that are roughly semielliptical are obtained by means of the mathematical description of the potential field surrounding an ellipsoidal cavity. An algorithm selects the ideal semiellipse that best fits the potential readings.

Nuclear plant monitoring requires a measurement system suitable for remote operation, with long-term stability that is not influenced by temperature changes. Several innovations and refinements make the reversing dc system unusually stable and sensitive. Crack growth rates of a few thousandths of an inch per year can be resolved by some laboratory systems. Reversal of current polarity at half-second intervals compensates for thermoelectric effects. Multiple potential readings (typically 16) are made before and after each current reversal, and these are averaged to enhance the signal-to-noise ratio. The potential readings for active probes are normalized to a reference probe potential to compensate for changes in current or in temperature-dependent material properties. Use of dc permits placement of long, unshielded leads between the probe attachments at the component and the amplifier or nanovoltmeter at which the potential is measured.

Pipe crack monitor

In RP2006-12 researchers measured the growth of internal pipe weld defects in the laboratory by attaching probes inside the pipe near the crack face, but the procedure is difficult at best and inapplicable in the field. One objective of this project and its predecessor, RP2006-3, was to develop a way of monitoring an internal pipe crack by using external, nonintrusive electric probes. An analytic study showed that probes attached to the surface opposite a crack could monitor surface cracks in a pipe or plate with a useful degree of accuracy. The crack must first be located by another technique, such as ultrasonics, and the surface-mounted leads must be accurately placed with respect to the crack. Given these conditions, the electric potential difference across an external pair of probes is quite sensitive to increases in the depth of a long, shallow crack. The technique is less sensitive to growth of a semicircular defect, but the latter is of much less consequence to the structural integrity of the piping system.

In a laboratory demonstration at General Electric's Corporate Research and Development Laboratory in Schenectady, New York, internal defects in a 4-in stainless steel pipe were propagated by low-cycle fatigue while the pipe was filled with 290°C water. The crack enlargement measured with external probes (Figure 2) showed good agreement with the

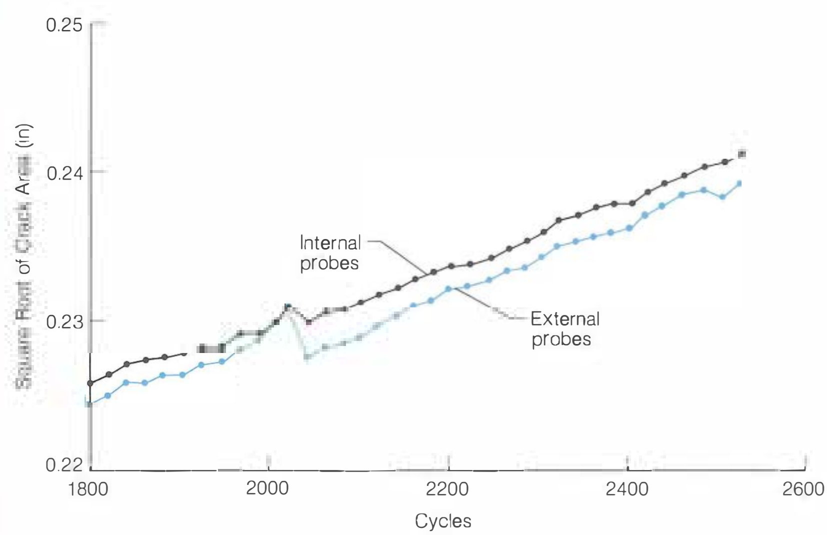
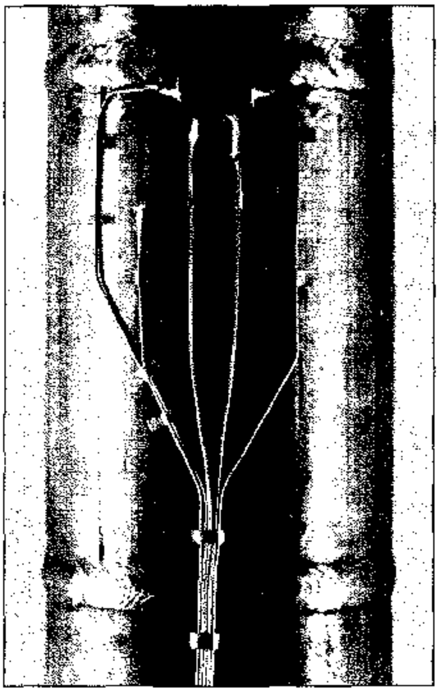


Figure 2 Crack enlargement data for a pipe similar to the one in Figure 3. The discontinuity results from the selection of a slightly different best-fit crack shape by the data-matching algorithm. The crack length is about 12 times the depth.

Figure 3 Electrical leads have been spot-welded to a 4-in pipe at an internal stress corrosion crack. The algorithm for data interpretation makes adjustments for missing or mislocated probes.



crack size derived from internal probes and from posttest destructive examination.

Figure 3 shows a 4-in pipe in General Electric's Pipe Test Laboratory in San Jose, California, equipped with external probes at an internal corrosion crack location. The material and environment are conducive to intergranular stress corrosion cracking (IGSCC). Tests currently in progress show a gradual increase of potential during periods of constant loading that is indicative of IGSCC. These tests are part of a project to assess degraded pipe repairs for the BWR Owners Group II under RPT302-1.

Techniques for monitoring small pipes must be modified for application to large pipes in field applications because passing a uniform current down a large pipe to create the potential field is not practical. The current source and sink must be located close to the crack to keep current requirements low. Work being conducted under RPT302-1 will determine optimal probe locations and modify the analytic calibration model as required for large-pipe applications.

Many IGSCC pipe cracks in operating plants have been reinforced by application of a weld overlay, and there is incentive to monitor representative repairs in the field to confirm the satisfactory long-term performance of this repair technique. Monitoring a crack beneath a weld overlay requires some further modification of the large-pipe calibration model to accommodate the thickness discontinuity in the pipe wall. A laboratory demonstration of IGSCC monitoring of a 12-in weld overlay repair is planned for early 1986.

The calibration model for pipe crack monitoring characterizes the crack as the semiellipse for which the potential measurements most nearly conform to the mathematical calibration model. Cracks having well-defined length and depth should be adequately represented by this idealization. If the crack shape is very irregular, as it may be for some IGSCC pipe cracks, a source of error is introduced. The accuracy of the pipe crack monitor in practical field applications is likely to be limited primarily by this factor.

Stress corrosion cracking sensor

The behavior of hypothetical or inaccessible cracks in reactor components can be assessed with a stress corrosion cracking (SCC) sensor of similar material and exposed to the same environment. For example, standard precracked fracture mechanics specimens of several materials have been installed in an autoclave in Commonwealth Edison Co.'s Dresden-2 plant and exposed under stress to reactor coolant. Crack growth data measure the effectiveness of hydrogen water chemistry in suppressing stress corrosion cracking in these materials. These sensors aid in establishing the limits of benign water chemistry conditions, and they could also serve to measure the extent of SCC damage that results from transient off-normal water chemistry conditions. Similar installations are planned in at least two other domestic plants and in a Swedish plant.

An alternative to in-plant installation of an autoclave and loading mechanism is a preloaded, precracked sensor that can be inserted directly into the reactor at a location where the environment is similar to that of the component of interest. The sensor must be mechanically and functionally reliable, and it should also be compact and self-loaded. A wedge-loaded double cantilever beam sensor has been designed to meet these requirements. Side grooves maintain the crack in its plane, and a series of potential probe pairs along the beam provide a very sensitive indication of crack extension. The size, shape, and dimensions of the sensor are selected to maintain the desired crack stress intensity without loss of load that results from stress relaxation. Electrical leads may be routed inside rather than outside the sensor to minimize the likelihood of damage or loose parts.

The SCC sensor is the product of a joint EPRI–General Electric project (RP2006-12). The first in-plant application of the sensor is expected to be an in-core installation in 1986. The objective of that effort will be to acquire data on irradiation-assisted SCC in an environment that cannot be simulated outside a reactor.

Stress corrosion monitoring system

A capability for direct measurement of accumulated SCC damage over a period of time suggests application to residual life assessment of susceptible components. Elements of a life prediction methodology are the crack growth response of the sensor, the projected stress changes in the component, and a predictive model that relates crack growth rate to stress, time, and temperature. The sensor response is key information that characterizes the effect of the environment at the crack. Loading history at the component, which differs from that at the sensor, could be estimated from existing plant instrumentation or through additional sensors. Reliable predictive models for environmentally assisted crack growth rates are emerging from a separate line of EPRI-sponsored research at General Electric under RP2006-6. Project personnel envision that an on-site microcomputer with data acquisition, analysis, and display functions would process this information.

There are both short-term and long-term incentives for the development of such a system. Plant operators receive immediate feedback on the damage consequences of unplanned water chemistry transients and are able to gage the required time for corrective action to minimize damage. Planned procedures, particularly those involving off-normal water chemistry, can be tailored or optimized to increase component life and reduce repair outage costs. Component life prediction based on in-plant monitoring could also be useful in determining appropriate inspection intervals.

In principle, crack growth in defective components can be predicted without in-plant measurements. If the materials, the environment, the defect, and the stress are defined and if models are available for relevant material-environment combinations, the crack growth rate and the component life can be predicted. In practice, the reliability of such predictions is limited by uncertainty in some of the relevant parameters or in the model itself. A stress corrosion monitor provides a means of confirming the predictive model or of better characterizing the environmental parameters under conditions that are well controlled with respect to stress and material variables. The corrosion monitoring system will be useful if resulting predictions are sufficiently reliable to support decisions that extend component life or avoid unnecessary outage costs. *Project Manager: J. D. Gilman*

New Technical Reports

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

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

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

EPRI also has a report summary program available without charge to members and by subscription to nonmembers. Each summary provides a concise one-page description of the published report. For information on how to order report summaries, please contact the EPRI Technical Information Division, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2411.

ADVANCED POWER SYSTEMS

Benefits of Improved Gas Turbine Reliability

AP-4162 Final Report (RP1187-10); $32.50
Contractor: Power Technologies, Inc.
EPRI Project Manager: C. Dohner

Two-Stage Coal Liquefaction Studies

AP-4185 Final Report (RP1715-1); Vol. 1, $32.50; Vol. 2, $25.00
Contractor: Kerr-McGee Corp.
EPRI Project Manager: C. Kulik

High-Reliability Combined-Cycle Program Study

AP-4191 Final Report (RP1187-3); $32.50
Contractor: General Electric Co.
EPRI Project Manager: C. Dohner

Radiation Heat Transfer in Coal Gasification Systems: Research Planning Study

AP-4213 Final Report (RP1654-28); $25.00
Contractor: Stanford University
EPRI Project Manager: G. Quentin

Proceedings: Tenth Annual EPRI Contractors' Conference on Clean Liquid and Solid Fuels

AP-4253-SR Proceedings; $85.00
EPRI Project Manager: H. Lebowitz

EPRI Wind Turbine Test Activities, 1983–1984

AP-4288 Final Report (RP1996-11); $32.50
Contractor: Burns & McDonnell Engineering Co.
EPRI Project Manager: F. Goodman

COAL COMBUSTION SYSTEMS

Influence of Coal Particle Size on Coal-Water-Slurry Fuel Combustion

CS-4233 Final Report (RP1895-12); $32.50
Contractor: Energy and Environmental Research Corp.
EPRI Project Manager: C. Derbidge

Dissimilar-Weld Failure Analysis and Development Program

CS-4252 Final Report (RP1874-1); Vol. 1, $25.00; Vol. 2, $32.50; Vol. 4, $55.00; Vol. 5, $25.00
Contractor: The Metal Properties Council, Inc.
EPRI Project Manager: R. Viswanathan

Coal-Water-Slurry Test in an Industrial Boiler

CS-4268 Final Report (RP1895-7); $32.50
Contractor: E. I. du Pont de Nemours & Co., Inc.
EPRI Project Manager: R. Manfred

Condenser-Targeted Chlorination Design

CS-4279 Final Report (RP2300-2); $47.50
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: W. Chow

Bimodal Processing of Titanium Steam Turbine Blades

CS-4280 Interim Report (RP1264-1); $25.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: R. Jaffee

Proceedings: Condenser Biofouling Control—State-of-the-Art Symposium

CS-4339 Proceedings (RP2300-2); $92.50
Contractors: Meeting Planning Associates; Stone & Webster Engineering Corp.
EPRI Project Manager: W. Chow

ENERGY ANALYSIS AND ENVIRONMENT

Marketing Demand-Side Programs to Improve Load Factor

EA-4267 Final Report (RP2050-11); Vol. 1, $25.00; Vol. 2, $32.50; Vol. 3, $32.50
Contractor: Synergic Resources Corp.
EPRI Project Manager: C. Gellings

Legionnaires' Disease Bacteria in Power Plant Cooling Systems: Downtime Report

EA-4300 Final Report (RP1909-1); $25.00
Contractor: Oak Ridge National Laboratory
EPRI Project Manager: J. Mattice

Feasibility and Design of the Massive Aerometric Tracer Experiment (MATEX)

EA-4305 Final Report (RP2434-2); Vol. 1, $32.50; Vol. 2, $55.00
Contractor: Environmental Research & Technology, Inc.
EPRI Project Manager: R. Patterson

Estimating Air Conditioner Loads Using Available Billing and Weather Data: Exploratory Analysis

EA-4309 Interim Report (RP2145-2); $25.00
Contractor: Energy and Resource Consultants, Inc.
EPRI Project Manager: S. Braithwait

ENERGY MANAGEMENT AND UTILIZATION

Performance of Air-Source Heat Pumps

EM-4226 Final Report (RP1495-1); $32.50
Contractor: General Electric Co.
EPRI Project Manager: J. Calm

Harmonics and Electrical Noise in Distribution Systems: Measurements and Analyses

EL/EM-4290 Final Report (RP2017-1), Vol. 1; $32.50
Contractor: SRI International
EPRI Project Manager: W. Shula

Assessment of Centralized Medium-Sized Fuel Cell Power Plants

EM-4332 Final Report (RP1041-20); $32.50
Contractor: Kinetics Technology International Corp.
EPRI Project Manager: E. Gillis

Plasma Processing in the U.S. Chemical Industry

EM-4336 Final Report (RP2416-25); $40.00
Contractor: Science Applications International, Inc.
EPRI Project Manager: L. Harry

NUCLEAR POWER

Intergranular Attack of Alloy 600: Laboratory Investigations

NP-4223 Interim Report (RPS302-4); $25.00
Contractors: Commissariat à l'Energie Atomique; Framatome
EPRI Project Managers: J. Paine, D. Cubicciotti

Steady-State Radiation Embrittlement of Reactor Vessels

NP-4224 Final Report (RP1021-3); Vol. 1, $25.00; Vol. 2, $40.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: S. Tagart

Fuel Channel Lifetime: Expansion of Statistical Predictive Models

NP-4225M Final Report (RP1943-1); $25.00
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: J. Santucci

Test Fuel Rod Irradiation in 14 × 14 Assemblies at Calvert Cliffs-1

NP-4230M Final Report (RP586-1); $25.00
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: J. Santucci

Development of Cobalt-Free Hard-Facing Alloys for Nuclear Applications: 1984 Progress

NP-4237 Interim Report (RP1935-5); $25.00
Contractor: AMAX Materials Research Center
EPRI Project Manager: H. Ocken

Remote Reconnaissance Vehicle Program

NP-4265 Final Report (RP1544); $32.50
Contractor: General Public Utilities Nuclear Corp.
EPRI Project Managers: N. Hirota, K. Winkleblack

Index to 1985 EPRI Journal

ELECTRIC POWER RESEARCH INSTITUTE
Post Office Box 10412, Palo Alto, California 94303

NONPROFIT ORGANIZATION
U.S. POSTAGE
PAID
PERMIT NUMBER 173
MILPITAS, CALIFORNIA

EPRI JOURNAL

ADDRESS CORRECTION REQUESTED

January/February 1986