

Flue Gas Desulfurization

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Cover: Wet scrubbing removes SO₂ in flue gas by showering the gas with an alkaline reagent slurry. Sulfur is absorbed in the slurry, leaving clean gas for stack emission. This wet process is used in about 85% of utility desulfurization systems.

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Problems and Progress in SO₂ Control



Environmental control devices on a new coal-fired power plant today can represent nearly half of the cost of the plant, and the single most expensive element is the flue gas desulfurization (FGD) system. Utilities have resorted to these systems, notably wet scrubbers, because of increasingly stringent SO₂ control requirements. The number of scrubbers has increased from a handful of units in the early 1970s to 94 units in operation by 1982, and 128 more are planned or under construction.

Unfortunately, the regulations driving FGD use have not always recognized the state of technology development, and early wet scrubbers designed to meet regulations proved to be costly and unreliable. As a result, many utilities in the mid-1970s opted to burn more expensive low-sulfur coal to avoid the cost and operating problems of SO₂ scrubbers. In the late 1970s, amendments to the Clean Air Act resulted in even more stringent regulations on SO₂ removal for new plants, and for all intents and purposes, FGD became mandatory for all new coal-fired plants. This month's cover story reviews the industry's experience with wet scrubbers and the recent progress made in scrubber design and operation.

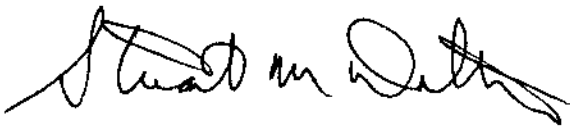
Although U.S. utilities and suppliers have come a long way in improving FGD technology, they have not yet developed an optimal wet scrubber system that offers both high reliability and low cost. In the past, utilities have had to accept partially developed methods of SO₂ control as a means of meeting regulations; now they are taking the lead in developing ways to make these systems operate more reliably and at lower cost to the consumer.

EPRI's role in FGD technology is not only to function as an information clearinghouse for the industry on what has been learned but also to help provide solutions to problems of chemistry, materials science, and control methodology to help

utilities and suppliers address the central cost and reliability issues. Further, EPRI is anticipating the problems FGD systems will face in the future, as even tighter restrictions on wastewater and solid by-products are adopted. Through an aggressive program that includes basic research, pilot tests, and demonstrations of new technology at utility sites, we are working on a host of such interrelated problems.

Increased flexibility offers the best hope for more-effective SO₂ control in the future. The proper application of research results through a more cooperative effort by users, suppliers, and government can overcome the deficiencies of wet scrubbing; but in many cases, alternative SO₂ control strategies, such as coal cleaning, use of low-sulfur coal, or coal blending, will be the most effective method of control. Application of a full range of compliance options developed to meet the needs of the environment and the economy should be encouraged. This would foster technological innovation and orderly development of improved SO₂ control technology.

Both the utility and the consumer can gain from such flexibility. If the utility is allowed to meet the emission control goal through a combination of approaches, engineering creativity from suppliers and utilities will be encouraged, and more-effective, more-economical systems will be the result. Through cooperation, the cost to the utility, the customer, and ultimately to the environment and society can be minimized.

A handwritten signature in black ink, appearing to read "Stuart M. Dalton". The signature is fluid and cursive, with a large initial "S" and "D".

Stuart M. Dalton
Program Manager, Desulfurization Processes
Coal Combustion Systems Division

Authors and Articles

Although utilities began to install flue gas scrubbers at coal-fired power plants 10 years ago, this category of pollution control equipment still poses problems of high cost and unreliability. Why this is so and what is being done about it are reviewed by science writer William Nesbit in this month's lead article, **Scrubbers: The Technology Nobody Wanted** (page 6). Nesbit's technical resources were three EPRI staff members who together have 17 years of experience in the Desulfurization Processes Program.

Stuart Dalton, the program manager, came to EPRI in October 1976 after four years with Pacific Gas and Electric Co. Much of his utility work involved coordination of pollution control system studies and design review of new technologies for steam generation, fuel and gas cleanup, and combustion modification. Still earlier, Dalton was a field service engineer with Babcock & Wilcox Co. He is a chemical engineering graduate of the University of California at Berkeley.

Thomas Morasky, with EPRI since August 1976, guides a subprogram of research in nonregenerable scrubbing processes. He was previously with The Detroit Edison Co. for 10 years, supervising the design, development, and operation of several flue gas scrubbers. Morasky graduated in chemical engineering from the University of Detroit.

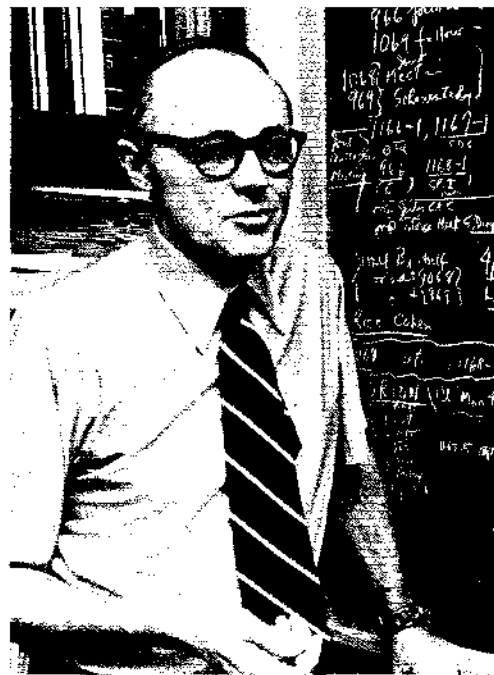
Richard Rhudy has been a project engineer in desulfurization research since December 1977. For nine years before coming to EPRI, he was with Bechtel Group, Inc., where he specialized in flue gas treatment and sludge dewatering processes. For three years he was responsible



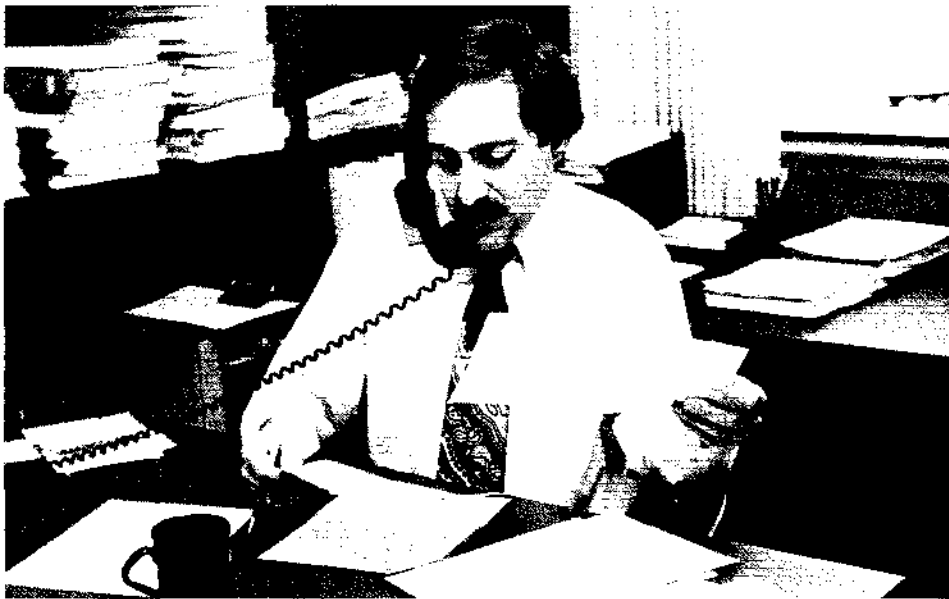
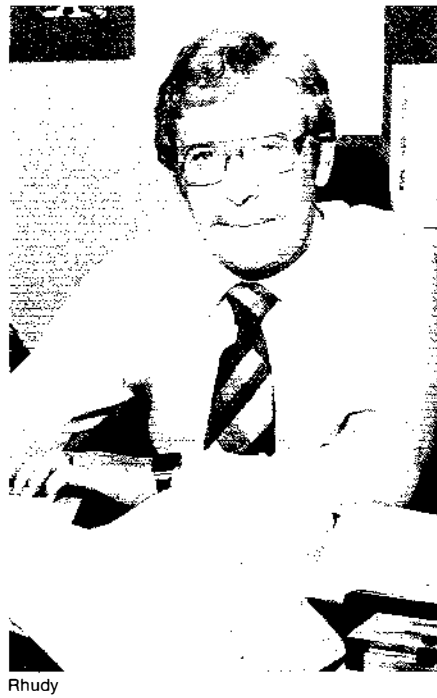
Dalton

for flue gas characterization at the scrubber test facility directed for EPA by Bechtel at TVA's Shawnee power plant. Rhudy has a BS in chemical engineering from the University of California at Berkeley.

About to go commercial in the United States is the first new energy storage option to break into the utility market in 50 years and the first new power generation option in 25 years. **Breaking New Ground With CAES** (page 16) reports the problem and the solution that found each other in the operations of a rural cooperative power utility in Illinois. The article was written by Nadine Lihach, senior feature writer for the *Journal*, who turned to Robert Schainker of EPRI's Energy Management and Utilization Division for



Passell



background in compressed-air energy storage.

Schainker has been at EPRI since July 1978, managing research in advanced techniques for energy generation and storage. He was formerly with Systems Control, Inc., for nine years as a research program engineer and manager in energy-environmental studies. Schainker holds a BS in engineering science, an MS in systems engineering, and a PhD in applied mathematics, all from Washington University (St. Louis).

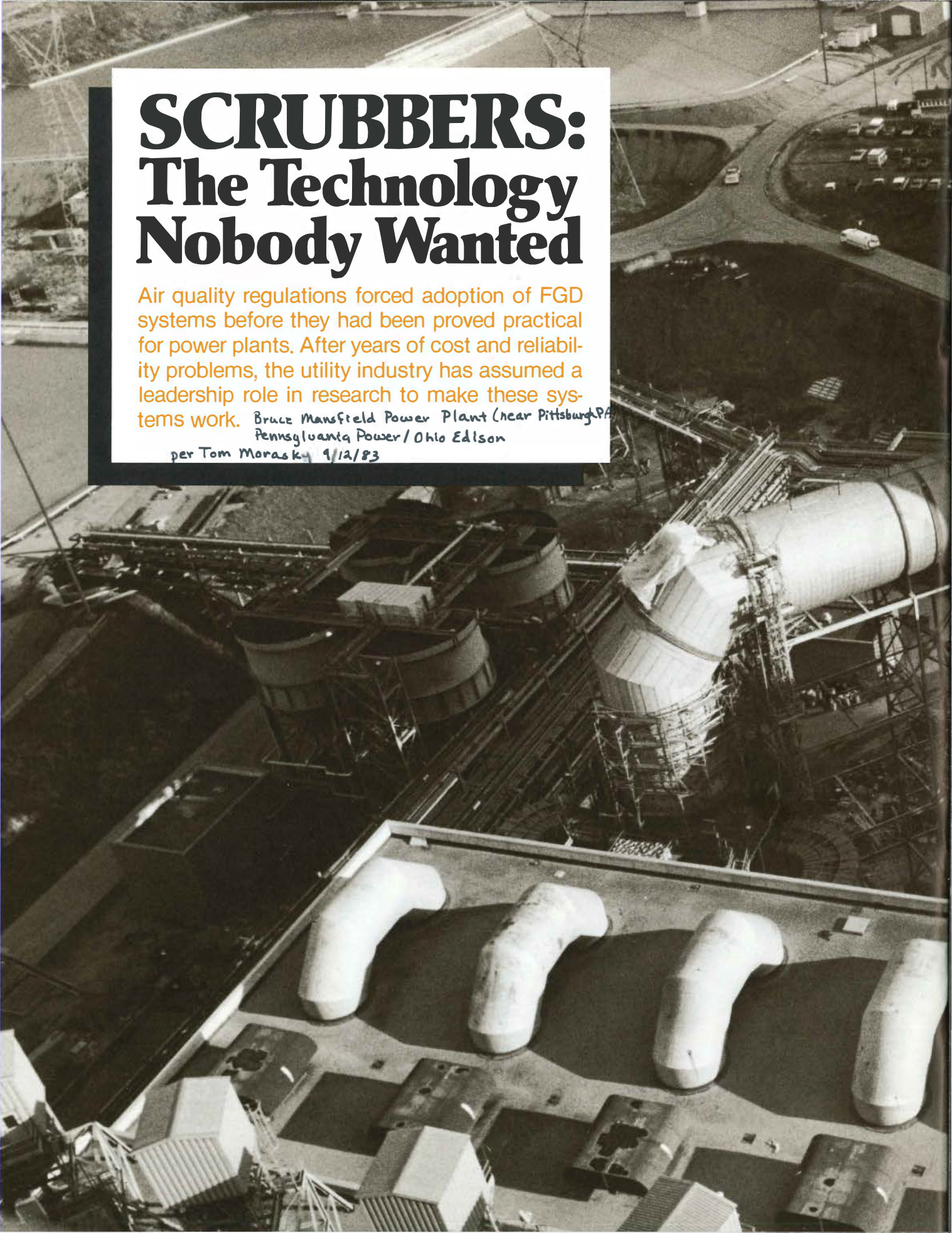
Whether as feedwater or as steam, 10 million pounds of working fluid circulate through a large power plant every hour. Even at concentrations of only a few parts per billion, some impurities in this flow can cause corrosion in nearly every component of the plant. **Steam Purity in PWRs** (page 22) reviews research findings and reports on steam purification methods being used and evaluated at three PWR power plants. Jenny Hopkinson, *Journal* feature writer, developed the article with technical assistance from EPRI's Thomas Passell.

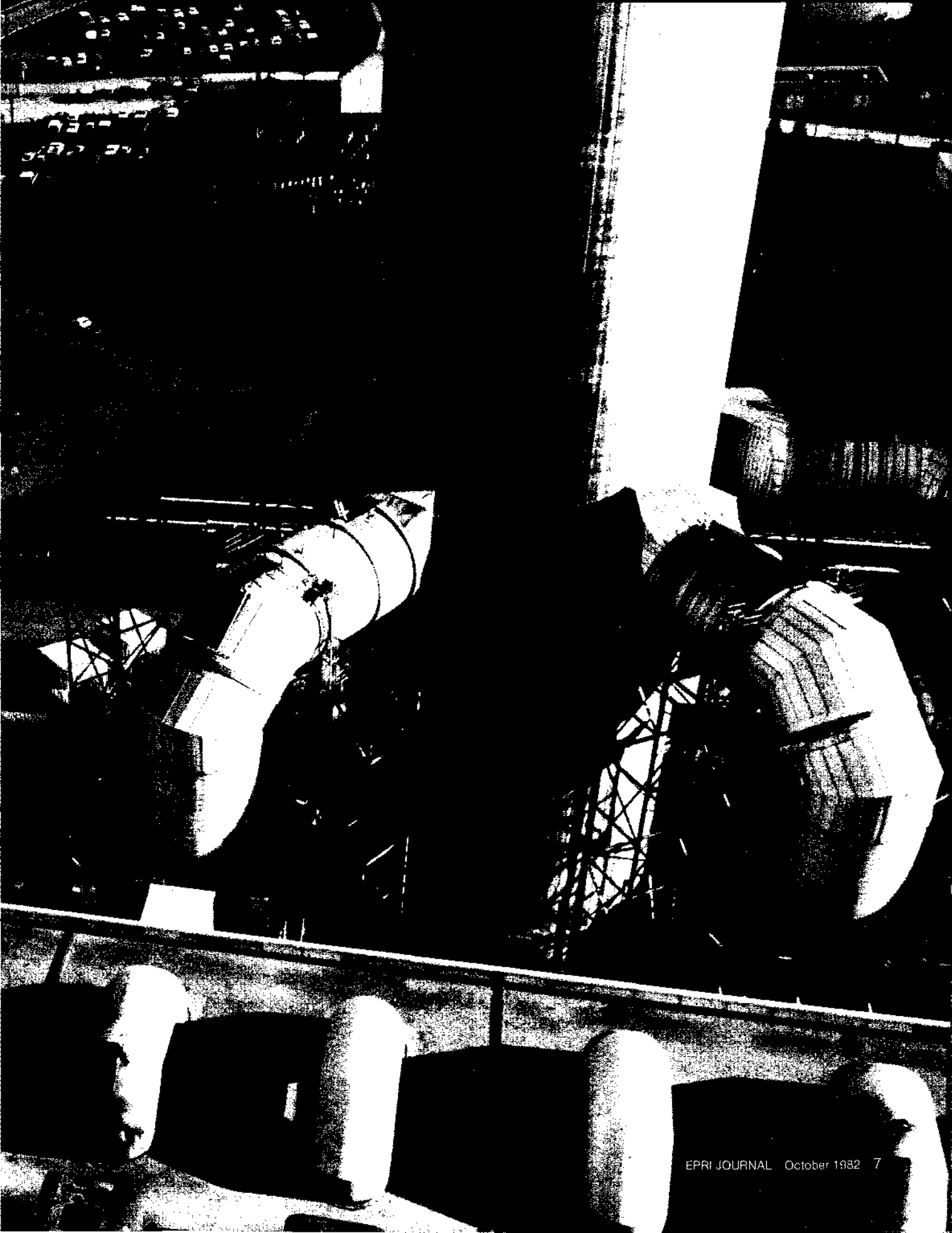
Passell has managed Nuclear Power Division research projects in water chemistry and corrosion control since June 1975. His background in radiochemistry, diagnostics, and instrumentation was developed during 4 years as a staff scientist with Lockheed Missiles and Space Co. and 13 years as a senior physicist with SRI International. Passell holds BS and PhD degrees in chemistry from Oklahoma State University and the University of California at Berkeley.

SCRUBBERS: The Technology Nobody Wanted

Air quality regulations forced adoption of FGD systems before they had been proved practical for power plants. After years of cost and reliability problems, the utility industry has assumed a leadership role in research to make these systems work.

Bruce Mansfield Power Plant (near Pittsburgh, PA)
Pennsylvania Power / Ohio Edison
per Tom Morasky 9/12/83





Over the past decade, flue gas desulfurization (FGD) systems to control SO₂ emissions from coal-fired electric generating plants have proved to be among the most costly and least reliable pieces of equipment in the industry. Accounting for as much as 25% of the capital and operating cost of a new 1000-MW plant, conventional FGD systems—called wet scrubbers—have typically experienced severe corrosion problems and plugging and have not proved capable of reliable and efficient SO₂ capture.

And yet, over the next decade utilities will spend approximately \$1 billion each year for FGD equipment, a total higher than any other utility industry outlay for pollution control equipment of any kind. Already 220 FGD units are in place, under construction, or planned on utility coal-fired boilers, representing approximately 100 GW of capacity.

"There has been quite an evolution in wet-scrubber technology within the industry over the past decade," says Stuart M. Dalton, manager of the Desulfurization Processes Program in EPRI's Coal Combustion Systems Division. "Early on, the systems did plug and corrode badly, and many operators and others came to believe they were unworkable. But environmental regulations today are such that in most cases if the SO₂ control equipment on a plant isn't working, that plant must shut down or derate. Utilities just can't bear that sort of thing, not with coal plants representing over 50% of the installed generating capacity in the country. They have to make the units work more efficiently and reliably or they will compromise the primary function of the industry—to produce reliable power at the lowest cost."

Today, according to Dalton, the industry has come a long way in this regard. "The key," he says, "is that utilities have increased their understanding of system process chemistry and have learned to simplify system hardware and select better construction materials."

Wet scrubbing is a simple concept, but in practice it is complex and expensive. An alkaline reagent, usually lime or limestone, is mixed with water to form a slurry and then sprayed into the flue gas produced in the coal combustion process. The SO₂ present in the flue gas is absorbed in the slurry, and calcium sulfite and/or calcium sulfate precipitates out for disposal. "The thing to understand here," explains Dalton, "is that this is a chemical process, not a mechanical one, and the industry historically has had little experience with large chemical systems. When the first FGD systems were being installed, many utilities didn't even have a chemical engineer on staff. Gaining an appreciation for the difference between chemical and mechanical processes is an important part of the sophistication achieved in recent years."

Early FGD experience

In the mid to late 1960s, with initial promulgation of local SO₂ standards, electric utilities used wet scrubbing only as a last resort. During these early years there was serious doubt as to whether national controls on SO₂ were appropriate. And equally important, other options for mitigating the potential adverse effects of SO₂ emissions (dispersal by tall stacks, intermittent control by load or fuel switching, and coal-cleaning techniques) were less costly and just as effective in many instances. Moreover, these were operations utilities understood and with which they had experience.

But as national SO₂ control legislation and regulations evolved through the 1970s with the Clean Air Act Amendments of 1970 and 1977 and with the New Source Performance Standards of 1971 and their revisions in 1979, continuous SO₂ removal became a requirement rather than an option, and utilities began planning and constructing large numbers of scrubbers. Wet scrubbers had been used in other industries for decades (notably the copper, steel, and

petrochemical industries) and it was widely believed by regulators, vendors, designers, and some utilities that the transition to coal-fired boilers would be relatively straightforward.

But it was not. Instead, because of the unique characteristics of coal combustion flue gas, the systems proved extremely complex and difficult to operate in utility application. Utilities were working with gas as much as 1000 times less concentrated in enormous volumes—one million cubic feet a minute (472 m³/s) on a 300-MW plant, for example. As a result, the whole scale of the scrubbing task increased substantially, and problems never before seen or anticipated began to crop up.

"Unfortunately," says Kurt Yeager, director of EPRI's Coal Combustion Systems Division, "technology-forcing regulations that were promulgated ignored this lack of utility experience in FGD and the resultant impact on reliability and cost. Neither resources nor incentives were provided to aid the industry in resolving technical issues before premature commercial application was required. Until recently, in fact, each utility scrubber installation was essentially a prototype representing a one-of-a-kind design, often produced by a vendor that had no prior or subsequent utility experience. This lack of continuity and experience further delayed the orderly development of the technology."

Initially, many designers felt all they had to do was to thoroughly mix lime in a slurry with the flue gas and all the SO₂ would be captured. But it soon became apparent that if this reaction was not well controlled, plugging (blocking of gas passages) would occur from the uncontrolled formation of solid deposits. Problems were also encountered with corrosion and, subsequently, with construction materials.

On some systems where these problems surfaced, environmental regulations allowed flue gas to be bypassed around the scrubber to enable continued generation of electricity. For those util-

REGULATIONS AFFECT FGD USE



Requirements to install wet scrubbers and other FGD systems on electricity-generating plants could be greatly affected by two legislative proposals now being considered in Washington, D.C., to amend the Clean Air Act.

The first responds to concern over the potential effects of acid deposition, commonly referred to as acid rain. Researchers believe that this phenomenon occurs when gases released by combustion rise into the atmosphere, are converted to acid form, and then fall back to Earth in wet and dry forms. NO_x and SO_2 are gases of specific con-

cern, and in the United States today more than half of all man-made SO_2 emissions and approximately 30% of all NO_x emissions come from electric utilities.

Proposed acid rain legislation would substantially reduce current SO_2 and NO_x emissions, with the greatest impact imposed on coal-fired power plants built prior to the stringent standards required under the Clean Air Act's New Source Performance Standards. Implementation of this legislation would approximately double the existing utility requirement for FGD equipment and require an expenditure of tens of billions of dollars in capital costs for the equipment.

The second proposal would eliminate the so-called percentage reduction requirement. Currently, any new coal-fired generating plant, whether it uses low-sulfur or high-sulfur coal, must reduce its SO_2 emissions by 70–90%, depending on the coal's sulfur content, and under no circumstances may it exceed emissions of 1.2 lb SO_2 per million Btu of heat input to the boiler. The effect is that scrubbers are required for all new coal plants. Repeal of the percentage reduction requirement would benefit plants that burn low-sulfur coals by eliminating the need for scrubbers. □

ities that could not bypass, however, brute force was required to make the system work. At Kansas City Power & Light Co.'s La Cygne station, one of the eight wet-scrubber modules was shut down each night and thoroughly cleaned. This required a large maintenance staff and a significant premium in operating costs, but it was the only way to keep the plant on-line.

In search of answers to the problems they were experiencing, utilities turned to their vendors and architect-engineers, but these traditional sources of support were equally at a loss to understand the system dynamics and provide solutions. Moreover, each vendor seemed to have a different philosophy and different hardware that performed differently from application to application. For their part, regulators did not recognize the reliability and cost problems plaguing wet scrubbers and maintained the stance that if FGD worked in one industrial setting it should work in another. Moreover, they frequently cited experience in Japan, where wet scrubbers for SO₂ collection were apparently successful in utility settings on oil and a few low-sulfur coals.

"It was in this environment in the mid to late 1970s that utilities began to take matters into their own hands," comments Richard G. Rhudy, project manager in the Desulfurization Processes Program. "They saw that SO₂ controls were probably here to stay, and they began acting rather than relying on others to make FGD work effectively and efficiently. What this meant as a practical matter was that individually and through EPRI they began developing the data and evolving the understanding they needed on their own. They began testing and in the last year or so have begun writing their own system specifications and performance requirements."

System operation

Of the almost 200 types of FGD systems identified to date, wet scrubbers (or more formally, wet, lime/limestone,

nonregenerative systems) account for over 85% of the units operating in utility settings.

Typically, a wet scrubber is selected because it is the only alternative for meeting existing regulations. Wet as opposed to dry operation represents traditional practice for absorption of gases in industrial applications. Lime and limestone are both readily available and relatively inexpensive alkali reagents. And nonregenerative operation (one in which the reaction product is disposed of) is usually less expensive than recovery of a salable product, such as sulfur, sulfuric acid, or liquid SO₂. One variation on wet scrubbing that has gained some utility attention does include recovery of calcium sulfate (gypsum), which can be used in wallboard manufacture and as an additive in cements and agricultural products.

With wet scrubbing, flue gas leaving the boiler passes through particulate control equipment and sometimes a pre-scrubber, where it is cooled and any entrained chlorides are removed. It then enters an absorber, a large structure with nozzles at the top that continually shower the gas in a wet slurry made up of 90% water and 10% solids. SO₂ in the flue gas is absorbed in this slurry and then collected in a reaction tank, where it combines with the lime/limestone to produce water and calcium sulfite and/or calcium sulfate crystals. A portion of the slurry is then pumped to a thickener, where these solids settle out before going on to a filter for final dewatering. Following this, the calcium sulfite and/or sulfate is sometimes mixed with fly ash or with fly ash and lime to solidify it for disposal. If the product is calcium sulfate, however, it may be sold.

Cleaned flue gas flows to the top of the absorber with other flue gases, past the nozzles, and into contact with a mist eliminator designed to remove any large slurry droplets entrained in the gas stream from the absorber. The flue gas is often reheated at this point to give it buoyancy and to protect against the cor-

Three Options for SO₂ Removal

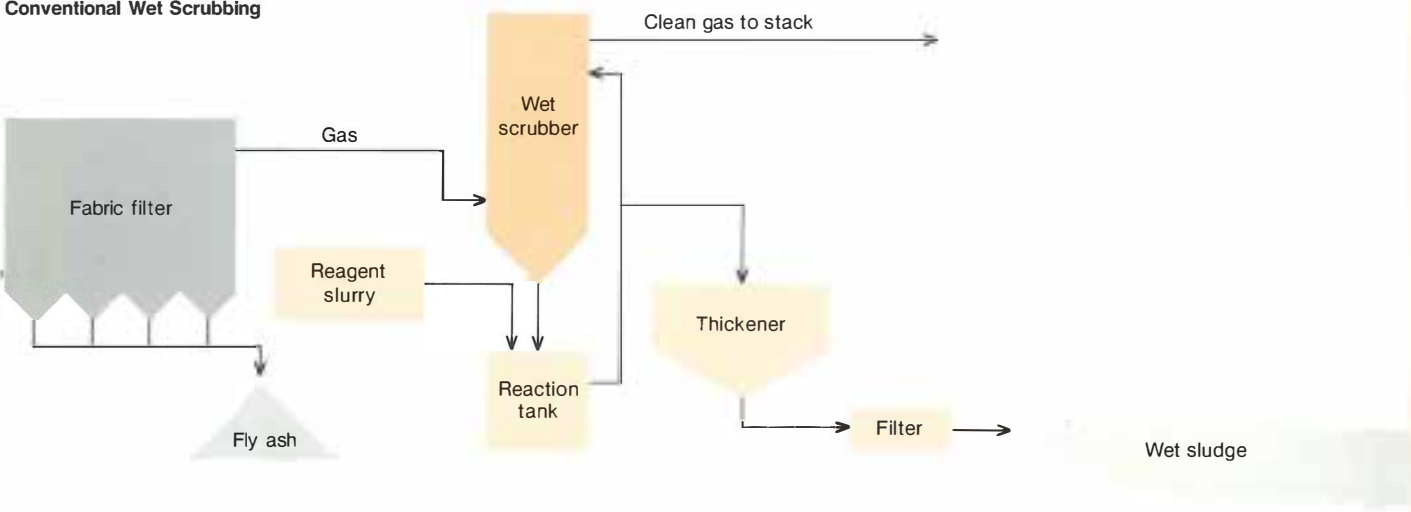
Wet scrubbing has been the standard utility desulfurization technology for over 10 years, but new, simpler desulfurization systems are being developed that could be less expensive and more reliable. In conventional systems, the flue gas is put through an electrostatic precipitator (ESP) or a fabric filter for particulate removal and then showered with an alkaline reagent slurry in a wet scrubber. After the SO₂ is absorbed, the scrubber slurry is thickened, filtered, and discarded in a disposal pond or landfill as wet sludge. Spray-drying systems use far less water than wet scrubbers; although the reagent still enters the system as a slurry, heat from the flue gas evaporates the water component as SO₂ absorption is occurring. The result is a dry waste that can be collected at the bottom of the spray dryer and by the fabric filter or ESP (along with particulate matter). The all-dry system injects a powdered reagent directly into the flue gas, and dry waste is collected by the fabric filter. The dry waste product of the new processes is both easier to handle and of smaller volume than wet sludge.

Flue gas

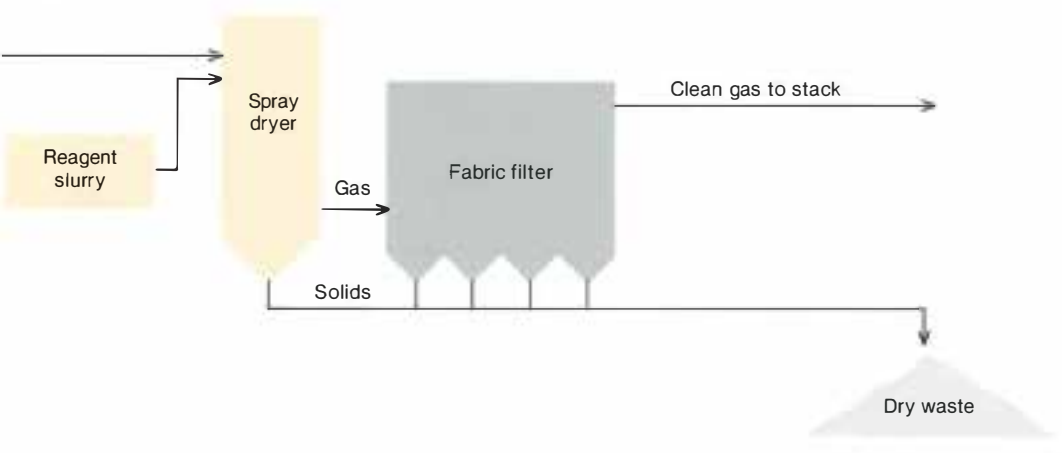
Flue gas

Flue gas

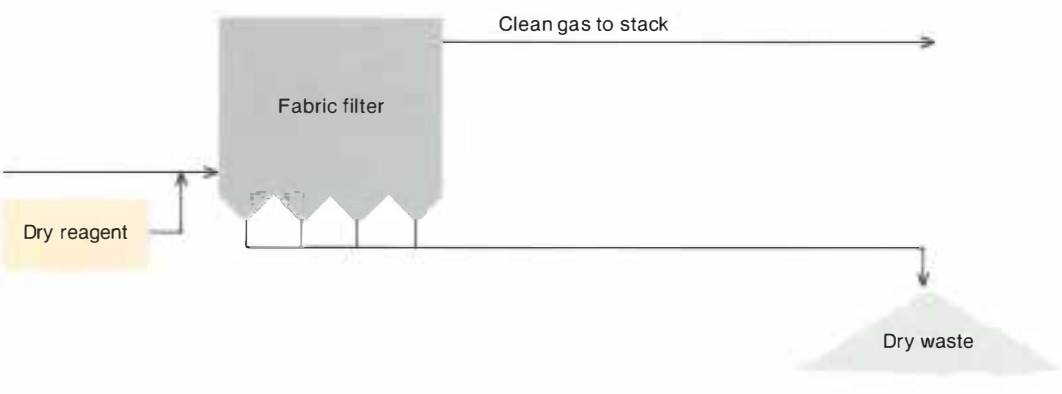
Conventional Wet Scrubbing



Spray Drying



All-Dry Process



rosion of downstream equipment. Finally, it is released out the stack.

Spray drying and the all-dry process

A promising and fast-growing alternative to wet scrubbing is spray-drying FGD. Here again the reagent is in wet-slurry form but is dried in the absorber by hot gas. As this drying takes place, the slurry reacts to trap the SO_2 . The dry product produced in this manner is then collected at the bottom of the absorber and in a downstream particulate collection device.

The primary advantages projected for spray drying over wet scrubbing are reduced energy use in pumping (1000 times less water is pumped), elimination of reheating, reduced water consumption, reduced concern about corrosion (flue gas leaving the absorber is not saturated with water), and the ease of handling a dry product.

Because of these perceived advantages, spray drying has gone from pilot testing to commercial application in the past five years, and at least 13 systems are now on order by utilities. However, because of system economics, the primary application for spray drying at present is on low-sulfur coals, and all utility systems now on order are for plants that burn this type of fuel. Other limitations and concerns with the technology center on the industry's scant experience with it in commercial application and on technical questions regarding such aspects of operation as reagent preparation, absorber residence time, saturation control, and operation of downstream particulate control equipment.

A simple and low-capital-cost alternative to wet scrubbing or spray drying now ready for commercial application is the all-dry process of SO_2 removal. All-dry systems do not require absorbers or slurry preparation and do not use water, thereby facilitating handling and eliminating the need for pumping and attendant energy use.

In all-dry operation, a powdered alka-

line compound (a dry sorbent) is injected into the ductwork ahead of a fabric filter (baghouse). This compound then collects on the fabric filter, capturing SO_2 as the flue gas stream moves through the filter cake. Reagent availability and cost represent potential obstacles to system application, however, and a number of technical questions remain to be answered concerning disposal, long-term effects on the fabric filter, composition of the reagent, and method of reagent feed control.

Steps in reliability improvement

Evolution of spray drying and new concepts, such as the all-dry process, clearly represent important developments in improving the reliability and cost of SO_2 collection. But because wet scrubbing is the preeminent method of SO_2 control for utilities today, cost and reliability improvements on these systems continue to rank as the industry's first priority in FGD research.

Since 1978 EPRI has conducted an R&D program with this specific focus. Now the largest of its type in the country, the program emphasizes improvements in process chemistry, materials of construction, energy and water use, data collection and interpretation, and hardware design.

Understanding the chemistry of wet scrubbing is an important first step in performance improvement. And according to Dalton, the industry has come a long way in this regard. The basic lesson learned is that proper control of slurry acidity and chemical composition is crucial to reliability. "By controlling the way solids come out of solution we can control the quality of the by-product and maintain relatively trouble-free scrubber operation," he says. "This process, called crystallization, really means taking the right solids out at the right place, preferably in the reaction tank, and at the right time to avoid plugging the absorber."

Understanding this crystallization process is an important part of the so-

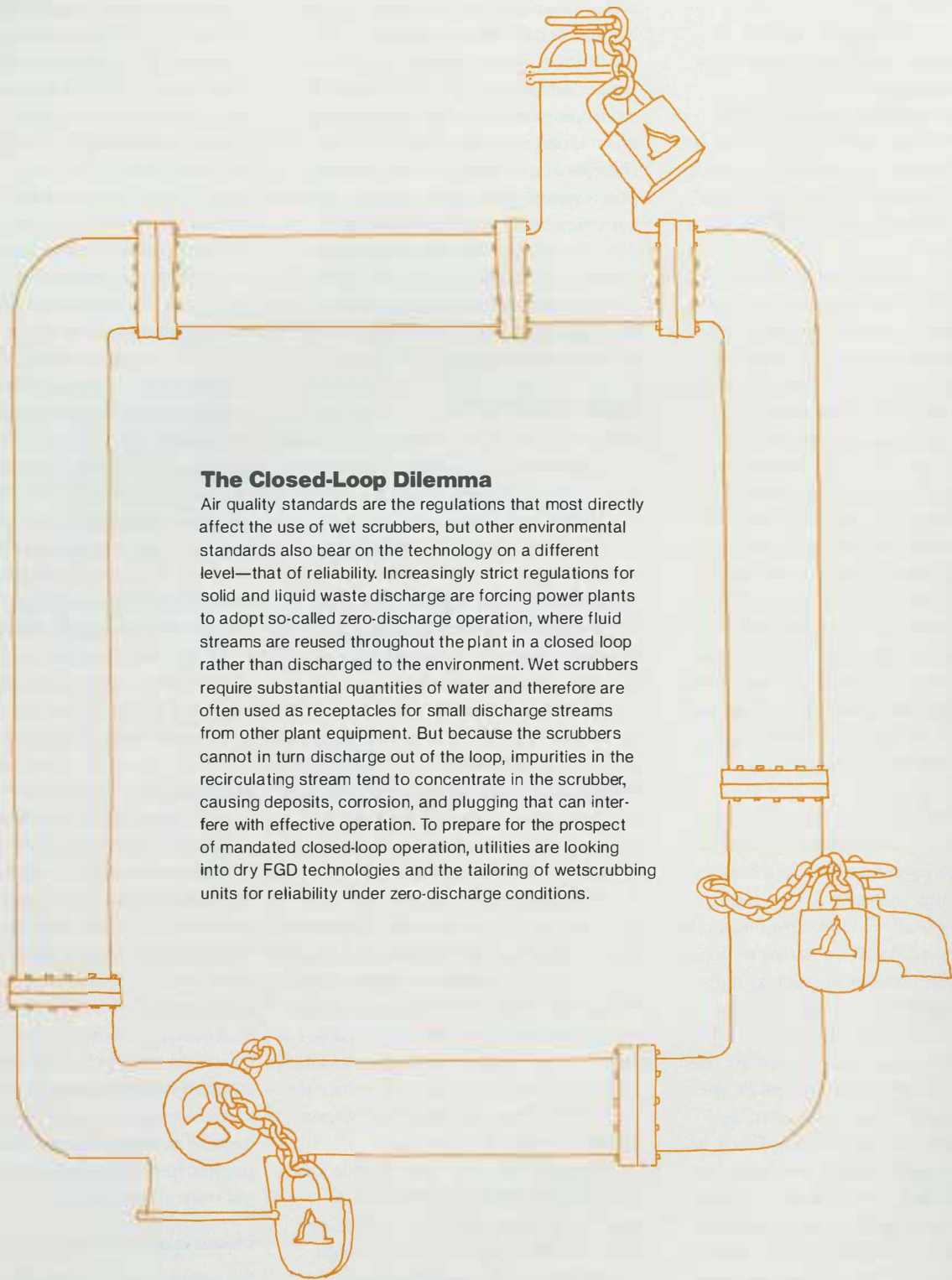
phistication the industry has gained in recent years in physical and chemical processes. It has led to better system design and thereby less costly operation, and it has enabled EPRI to design new hardware and predictive tools to help utilities tailor the end product they wish to produce.

Control of chemical processes is also important in terms of reagent preparation. How the reagent is ground (limestone) or slaked (lime), the type of water used in preparation, and the chemical composition of reagent raw material are crucial to both scrubber performance and reliability. Work is now under way at EPRI to identify the best preparation techniques, to determine the effect on SO_2 collection efficiencies of various chemical constituents in the reagents, and to test the effect of different types of water used in preparation (i.e., clean water versus process water from other plant equipment). Results to date indicate that significant performance and reliability dividends are possible with improvements in this area.

Materials improvement

With system chemistry becoming better understood, the biggest single problem in FGD operation today is materials failure as a result of corrosion. In the corrosive environment of FGD systems, some materials have been known to corrode or erode badly within a year or less. Six to seven years' service is now typical before substantial refurbishing is required, far short of the 30-40-year goal.

"In the evolution of wet-scrubber design, we have progressed from fairly conventional corrosion-resistant materials and coatings to more and more exotic and expensive materials," comments Thomas M. Morasky, EPRI subprogram manager in the Desulfurization Processes Program. "We've had some of the most exotic materials known to metallurgists corrode in some situations. When we first talked to suppliers they said, 'No problem, materials have been used in much worse environments with



The Closed-Loop Dilemma

Air quality standards are the regulations that most directly affect the use of wet scrubbers, but other environmental standards also bear on the technology on a different level—that of reliability. Increasingly strict regulations for solid and liquid waste discharge are forcing power plants to adopt so-called zero-discharge operation, where fluid streams are reused throughout the plant in a closed loop rather than discharged to the environment. Wet scrubbers require substantial quantities of water and therefore are often used as receptacles for small discharge streams from other plant equipment. But because the scrubbers cannot in turn discharge out of the loop, impurities in the recirculating stream tend to concentrate in the scrubber, causing deposits, corrosion, and plugging that can interfere with effective operation. To prepare for the prospect of mandated closed-loop operation, utilities are looking into dry FGD technologies and the tailoring of wetscrubbing units for reliability under zero-discharge conditions.

no corrosion troubles.' But as we've gotten into it, we've found that the demands on construction materials for scrubbers are much more severe than anyone anticipated."

Today, according to Morasky, the need for exotic construction materials is the number-one reason FGD units cost so much. Ductwork alone can cost as much as \$10 million on a 300-MW power plant.

Stainless steel and carbon steel are the most widely used materials, and some steels (mostly carbon) are lined with either organic linings and plastics (e.g., rubber, polyester, glass fiber-reinforced plastics, and fluoroelastomers) or ceramic and inorganic materials (e.g., refractory brick, concretes and mortars, and glass blocks). Nickel-based alloys and titanium are also being used.

Areas with the most extensive materials problems include outlet ducts, which are exposed to saturated, wet flue gas and condensed acids, as well as to fluorides and chlorides, and stack linings, which are exposed to many of the same conditions. Areas with moderate problems include prescrubbers, absorbers, reheaters, dampers, pumps, piping, and valves.

"We don't have all the answers on materials yet," says Morasky, "but we have learned quite a bit about how to pick the right material for the right service. For instance, our testing shows that for ducts and stacks operating under severe service conditions (such as high-sulfur bypass reheat), only the very highest nickel-based alloys and certain grades of titanium are appropriate metals, and that preferred nonmetals are acid-resistant brick and mortar, hydraulic cement, bonded glass block, and fluoroelastomer linings. We have a tremendous amount of data now, and the conclusion is that the use of ceramics and coatings and the judicious use of alloys can avoid most of the corrosion problems we've been experiencing."

EPRI's work in materials improvement involves laboratory investigations

to understand the mechanics and chemistry of corrosion and to identify promising materials; field-testing of promising linings, alloys, and coatings; and condensate sampling to test ductwork environments. Attention is also being given to determining if combinations of chloride and fluoride are possible culprits in some of the unexpected problem corrosion being experienced on new units. Exotic protection mechanisms such as cathodic protection and the use of corrosion protection additives in scrubber slurries represent other important research areas.

Design simplification

EPRI's work to improve reliability of wet scrubbers is also directed at simplifying system design. One result of this activity can be reduced energy use.

In a typical operation today, a wet scrubber uses 3–5% of total plant energy. Of this, pumping, pressure drop (the work done by fans to blow gas through scrubbers), and reheat account for approximately a third each.

EPRI's focus in reducing energy use centers on simplifying wet-scrubber system design. Elimination of prescrubbers by opening up absorbers to perform this function in a spray tower design is one option. This eliminates a separate operation and piece of equipment, and it lowers gas pressure drop, as well as slurry pumping requirements. Elimination of reheaters through proper design and use of wet stacks is another option. This could reduce energy consumption one-third. Additives that aid SO₂ absorption are also potentially important energy savers in that they can reduce the amount of slurry that must be pumped around the scrubber system.

Sparged scrubbing, whereby flue gas is forced through a tank of slurry as opposed to being showered with slurry in an absorber, is another new design concept that could significantly reduce system energy use by totally eliminating the need for recirculation pumps. EPRI-sponsored prototype testing of this ap-

proach to scrubbing has been performed with Gulf Power Co. and Southern Co. Services, Inc. A larger commercial demonstration is now planned to begin next year. Previous EPRI testing has already demonstrated high reliability while using limestone and producing a gypsum by-product.

As a result of these and other investigations, wet-scrubber energy consumption on new units can be reduced from about 5% to less than 2% of total plant energy use. On a 500-MW plant, this could result in savings in operating costs on the order of \$6 million a year.

A separate area of reliability improvement is gaining a better understanding of the trade-offs in system design and operation that affect plant performance and failure. A first step is a pilot program now under way to assemble current and historical information on the causes of system failures and to rank these causes by frequency and severity. Few objective data now exist in these areas, primarily because the National Electricity Reliability Council's generating availability and data system (NERC GADS) only recently began compiling information on FGD operation. Beyond data collection, attention is also being given to developing a method to analyze component reliability, identify the causes of unit outages, and evolve new hardware designs for components where problems have been experienced.

Problem hardware includes dampers, where opening and closing after periods of nonuse have been unsatisfactory; ductwork and stack design, where gas flow must be kept below velocities of 30–80 ft/s (9–24 m/s) (depending on surface roughness) to prevent reentrainment of surface condensation; and slurry pumps, for which design criteria have not been established.

Closed-loop operation

An emerging and potentially very important factor impacting wet-scrubber system performance is closed-loop power plant configuration, required for

zero-discharge plant operation. Work in this area, in fact, is rapidly becoming a major priority for utility R&D.

In closed-loop operation, wastewater is allowed to exit a plant only in a sludge or as a vapor out the stack. This requires tight control of water streams and has the effect of concentrating wastes in a limited cycle, which must be used again and again.

Increasingly stringent regulations on plant water intake and discharge are two forces driving closed-loop operation. However, some utilities have opted for modified closed-loop systems on their own initiative because by concentrating their waste streams they can reduce the amount of land they must set aside and maintain for waste disposal.

Closed-loop operation has significant implications for wet scrubbers inasmuch as wet scrubbers are net consumers of water and are typically located at the back of the plant. As a result, scrubbers will receive more and more concentrated wastes from other plant equipment when this equipment is operating under closed-loop conditions. The risk is that system chemistry will be upset and corrosion will increase.

"While no one in the utility industry is now operating with a fully closed loop," says Dalton, "this is clearly a trend of the future, and one the industry is anticipating rather well, we feel. In addition to independent investigations by individual utilities, EPRI is carrying out field tests at Colorado Ute's Craig station and at the R. D. Morrow Sr. power plant of South Mississippi Electric Power Association. Laboratory tests and computer simulations are also being performed to determine the potential effects of closed-loop operation on SO₂ scrubbing efficiency, crystal formation, scaling, and other parameters."

This work is complemented by separate testing and plans for pilot plant demonstrations of alternative FGD systems, such as spray drying and the all-dry process of SO₂ removal, which use little if any water and produce dry

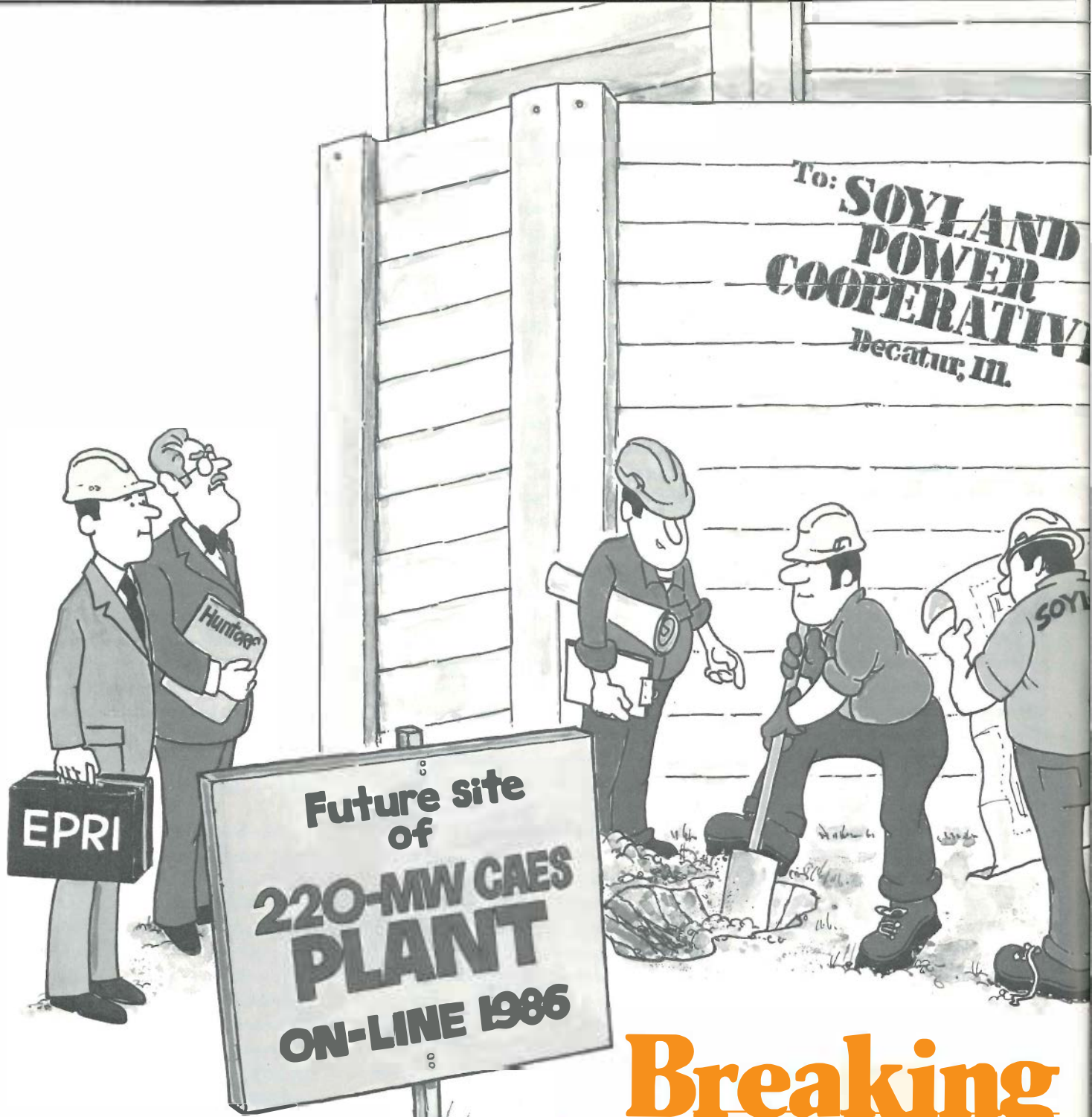
waste. This further work is centered at EPRI's Emissions Control and Test Facility at the Arapahoe station of the Public Service Co. of Colorado and is part of EPRI's integrated emissions control (IEC) approach to power plant operation. With IEC, SO₂ and other plant emission controls and flow requirements (air, liquid, and solid waste) are considered at the outset of design and from a systems perspective. This reduces the cost and improves the reliability of today's complicated environmental control processes, which collectively can amount to 40% or more of the total cost of a new coal-fired power plant.

According to Dalton, this broad-based and rapid response by the industry to the prospect of mandated closed-loop operation represents a significant development. A decade ago utilities had to be content with unproven technology for SO₂ control; by the end of the 1970s they had evolved to the point of writing their own system specifications; now they are well down the road in anticipating future problems and opportunities.

"I believe what we've seen and are seeing is a natural evolution in FGD system development," Dalton affirms.

"Utilities, if not yet legislators and regulators, have learned a great deal from the expensive lessons of the past decade in adopting wet-scrubber technology, and in the process they have assumed the leadership role in making the systems workable. This bodes well for the future of wet scrubbing and the other FGD technologies in which the utility industry and its customers will be investing billions of dollars." ■

This article was written by William Nesbit, science writer. Technical background information was provided by Stuart Dalton, Thomas Morasky, and Richard Rhudy, Coal Combustion Systems Division.



Breaking New Ground With CAES



Compressed-air energy storage (CAES) has never been used in the United States, but when a utility is hemmed in by the high cost of oil-fired peaking power and by limited storage options, there's always a first time. The utility industry is watching with interest as Soyland Power Cooperative develops its 220-MW commercial CAES unit.

Soyland Power Cooperative, Inc., was up against a problem that is miserably familiar to all too many utilities: how to get inexpensive peaking power. The Decatur, Illinois-based coop could get plenty of reasonably priced baseload power from neighboring utilities' coal and nuclear plants; Soyland even had one coal plant of its own planned for the near future, as well as a share in a nuclear plant. But peaking power, generated by costly oil and gas to instantly meet sudden surges in demand, was another story.

The only choice

In the oil drought that followed the 1973 Arab embargo, oil- and gas-fired peaking power had become increasingly expensive, and alternatives to it were maddeningly few. Surplus baseload power generated at night could be saved for use in peak periods, but energy was not easily stockpiled. One storage option was a pumped hydroelectric plant, which uses baseload electricity to pump water to an upper reservoir and then releases the water as needed to power a turbine. Pumped hydro, however, was site-limited, and was not suitable for Soyland's flat midwestern locale. An underground pumped hydroelectric plant was not feasible either: to be economical, it had to be large, not the relatively small unit that Soyland needed. And futuristic storage options like utility-size batteries just were not going to be available for another decade or so. Soyland was caught in a tight spot. Still, another option was available: compressed-air energy storage (CAES).

CAES splits the two basic stages of a conventional gas turbine, making the most of baseload power, while using the least peaking or intermediate fuel. During off-peak periods, inexpensive baseload electricity from coal-fired or nuclear power plants runs a combination motor-generator in a motor mode, which in turn operates a compressor. Air is compressed, cooled, and pumped into an underground

storage reservoir hundreds of thousands of cubic yards in volume and about two thousand feet (~610 m) below the surface. There the air remains, at pressures up to about 60 atm (6.1 MPa), until peaking or intermediate power is required. Then, the air is released into a combustor at a controlled rate, heated by oil or gas, and expanded through a turbine. The turbine drives the motor-generator in a generator mode, thereby supplying peaking or intermediate power to the grid.

Through this approach, a CAES plant can save about two-thirds of the costly oil or gas that a conventional gas turbine peaking system would require because in a standard gas turbine, two-thirds of the turbine's shaft power (supplied solely by oil or gas) goes into powering the compressor. In CAES the compressor is powered by off-peak coal-fired or nuclear power, freeing all the turbine's output for electricity generation.

At the time CAES came to Soyland's attention, the utility was strictly a transmission and distribution cooperative. It as yet operated no power plants, conventional or otherwise, and purchased all the power it sold to its 15 cooperative members. CAES's underground storage reservoirs, split generating cycles, and high pressures all might have sounded somewhat sophisticated for Soyland; yet when the utility considered CAES more closely, the idea did not seem so adventuresome after all. The requisite parts—turbines, compressors, clutches, generators, motors—were readily available, and had been for a long time. Even the necessary mining technology was established. Despite its novelty, CAES was no space-age, high-tech power plant.

The subtler aspects of CAES, including technical design issues, economic feasibility, and environmental effects, had also been studied closely by EPRI, DOE, and intrigued utilities over recent years. The most significant CAES study was an EPRI-DOE effort that involved Potomac Electric Power Co.; Middle South Services, Inc.; Public Service Co. of Indiana; Commonwealth Edison Co.; Illinois Power

Co.; Central Illinois Public Service Co.; and Union Electric Co. The study developed and evaluated three preliminary CAES designs (each involving a different method of underground storage), explored economic feasibility and environmental effects, and established a method for assessing the costs and benefits of such a plant relative to other options. The study, completed in 1981, concluded that CAES was definitely ready for commercialization.

But perhaps most encouraging of all, a commercial CAES plant had been running smoothly since 1978—the 290-MW, 50-cycle unit in Huntorf, West Germany. Owned by Nordwestdeutsche Kraftwerke and using two solution-mined salt caverns, the plant had provided up to 3.5 hours a day of peak electricity to customers ever since it began operation.

Soyland's pressing need for peaking and intermediate power, the immediate availability of CAES technology, the thoroughness of available studies, and the design and operating experience at Huntorf were all compelling arguments for Soyland to seriously consider a CAES plant. Since each utility's decision to build a given plant is specific to that utility's situation, Soyland made a preliminary feasibility study of CAES and discovered that a 220-MW facility could save the equivalent of more than 300,000 barrels of oil each year over gas turbines. The numbers were convincing, and in November 1980, with the enthusiastic recommendations of Soyland's Royal B. Newman (then executive vice president and general manager), the cooperative's board of directors voted its commitment to build a CAES plant. Negotiation began immediately with contractors and vendors for turbomachinery and construction proposals, as well as proposals for environmental, economic feasibility, and site studies.

A big step

The CAES plant would be a sizable task for Soyland. It would not only be the first CAES plant in the United States and the

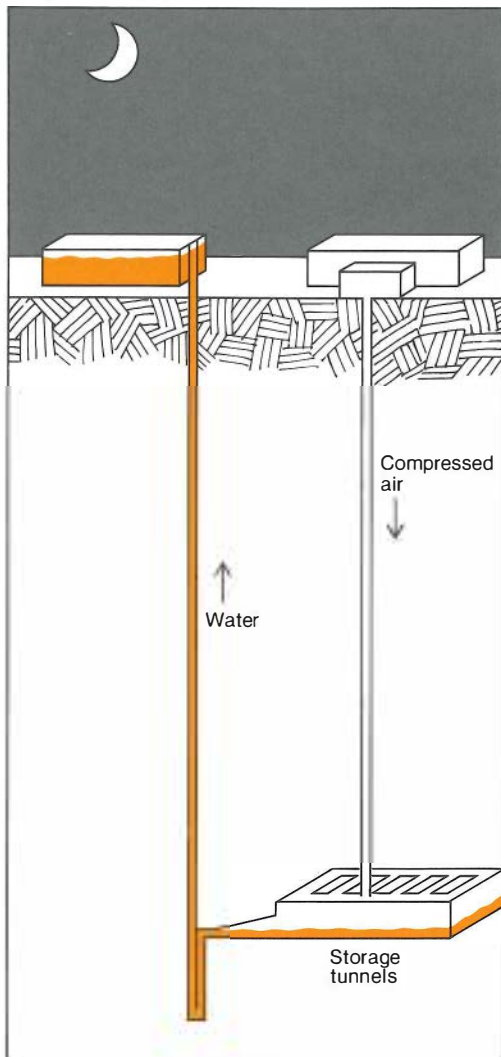
second in the world but also the first new storage option to break into the utility market in 50 years and the first new power generation option in 25 years. Soyland was growing rapidly, but its small engineering staff provided relatively modest manpower for such a momentous undertaking.

Soyland was not alone, however; throughout the rest of the industry, utilities in similar straits were curious about CAES. The chance to witness Soyland build a CAES facility from scratch to finish was too important to catch second-hand. On behalf of the utility industry, EPRI approached Soyland with an offer: EPRI's engineering advice and technical support in exchange for detailed information on the progress of the plant. As Robert Schainker, project manager for CAES in EPRI's Energy Management and Utilization Division, explains it, an engineer-of-record assigned by EPRI would chronicle the entire process, from preliminary feasibility studies to one year beyond final plant commissioning. Special in-plant monitoring and data-collection systems provided by EPRI would record plant startup and daily cycling operation for that year. Everything about this landmark plant would be recorded and made available to the entire industry. After the details of project management and coordination were worked out, Soyland agreed to the offer.

While contractor proposals were being negotiated and the Soyland-EPRI agreement was being made, Soyland took the critical step of seeking a permanent exemption for the plant from the Power Plant and Industrial Fuel Use Act of 1978. This law prohibits the use of precious oil in new power plants that operate over 1500 hours a year. Although the CAES plant would use vastly reduced amounts of oil compared with a conventional oil-fired peaking plant, it might well operate more than 1500 hours a year as a peaking or intermediate unit. An exemption was absolutely necessary before any contracts could be awarded. Soyland brought its case before DOE's Economic

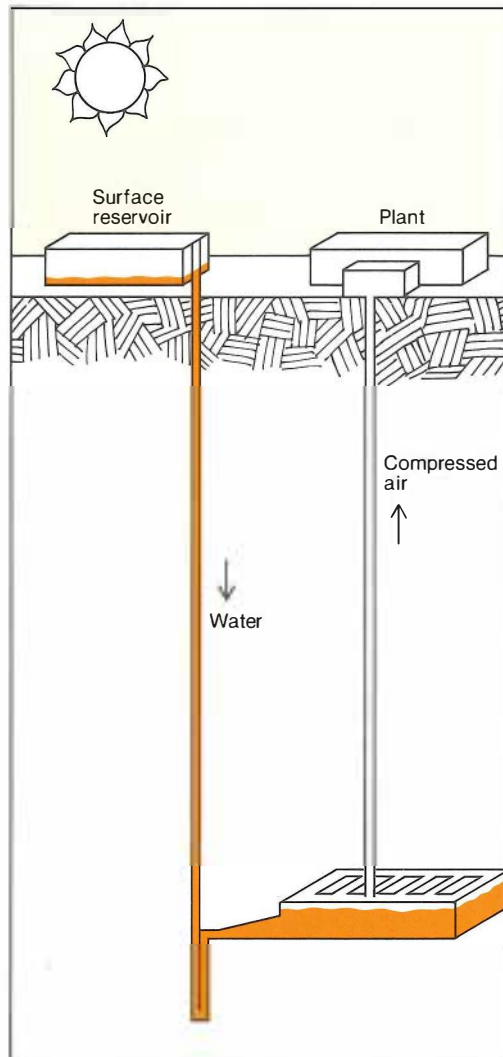
How Soyland's CAES Plant Will Deliver

Off-peak energy storage



During off-peak periods, inexpensive baseload electricity from coal-fired or nuclear plants will run a combination motor-generator in a motor mode, which in turn will operate a compressor. Air will be compressed, cooled, and pumped into underground storage tunnels excavated from hard rock. As the compressed air enters the tunnels, it will force a column of water up a shaft and into a surface reservoir; because the water keeps the air in the tunnels at a constant pressure, tunnel size can be minimized and excavation costs kept down.

Peak power generation



The compressed air will remain underground at a pressure of about 57 atm (5.8 MPa) until peaking or intermediate power is required. The air will then be released into a combustor at a controlled rate, heated by oil or gas, and expanded through a turbine. The turbine will drive the motor-generator in a generator mode, thus supplying peaking or intermediate power. As the air is released, water from the surface reservoir and shaft will enter the tunnels, maintaining the constant air pressure.

Regulatory Administration, and in April 1981, after a rigorous review, the agency granted the exemption based on the fact that a mixture of oil and electric energy was used to power the plant.

Fresh from this regulatory success, Soyland could now act on the many bids it had received for the plant's design and construction. Brown Boveri Corp., the U.S. subsidiary of the firm that built Huntorf, designed and will supply the necessary turbomachinery. The Cementation Co. of America, Inc., will design and build the storage cavern system. Reynolds, Smith, & Hills, Inc., was chosen to prepare plant specification bids, assess economic feasibility, and manage plant construction. The firm will also act as engineer-of-record for EPRI on behalf of the utility industry.

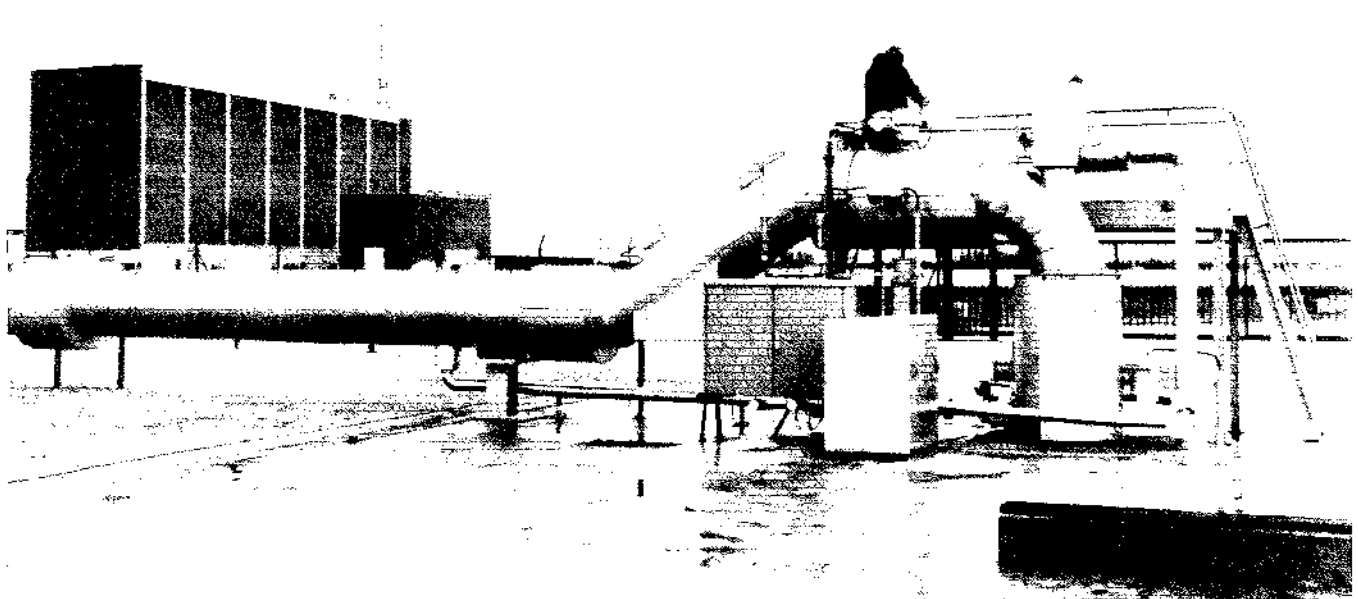
The plant, as finally envisioned, will be a 220-MW, 60-cycle facility. It will be built over excavated hard rock caverns—actually, a series of tunnels—a total of 275,000 cubic yards (210,253 m³) in volume. The surface features will include an ordinary switchyard, cooling towers, and turbine building. The caverns will be

filled daily with compressed air to a pressure of about 57 atm (5.8 MPa), which, when released, will provide up to 11 hours a day of peaking power.

Although the Soyland plant and its Huntorf predecessor are basically the same, there will be a few modifications at the new plant, according to Hans-Christoph Herbst, Nordwestdeutsche Kraftwerke's head engineer on the Huntorf project and now a consultant for EPRI. Since the new plant's air storage caverns will be built in hard rock rather than in a salt dome and because excavation costs are so much higher for hard rock, the Soyland plant will have water-compensated caverns. That is, water from a surface reservoir will flow downward through a vertical shaft to the caverns, displacing stored air during generation and enabling air in the caverns to remain at constant pressure. The process reverses during charging. Such a design requires only about one-sixth the volume of a salt cavern operating at variable pressure for the same energy-storage capability. The reduced volume spares considerable excavation cost.

The Soyland plant will also employ a recuperator (heat exchanger) to capture the waste heat of the turbine's exhaust gases, which will be used to preheat the compressed air that enters the turbines. This basically unremarkable engineering technique is expected to amount to a 27% savings in fuel efficiency.

Soyland has already selected a tentative site for the plant in Illinois' Pike County, conveniently across the road from Soyland's new 450-MW coal plant, scheduled to go on-line in 1987. Drilling at the site began early this year to verify the presence of a suitable rock formation 1800–2000 ft (549–610 m) below the surface. The test drilling will also check the airtightness of the rock below and its stability under the pressure changes that CAES will impose. If Soyland's geologic investigations go well and a suitable site for the CAES plant can be quickly pinpointed, designs can be finalized and construction can begin, probably by late 1983 or 1984. The new plant could then be providing electricity to Soyland customers in 1986, just four years from now.



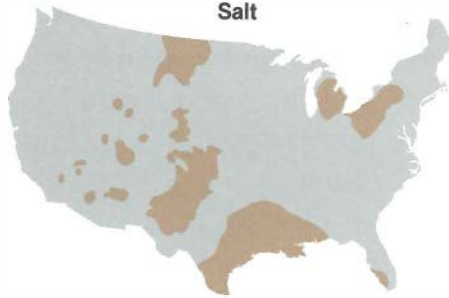
The world's first commercial CAES plant is in Huntorf, West Germany. This 290-MW, 50-cycle unit has been running smoothly since December 1978. Compressed air is stored in two solution-mined salt caverns.

Potential Compressed-Air Storage

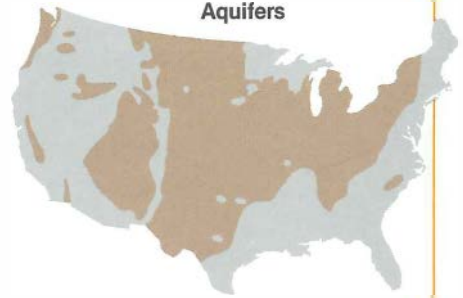
Rock



Salt



Aquifers



Soyland's CAES tunnels will be excavated from hard rock, but compressed air can also be stored in salt domes or aquifers. Perhaps three-fourths of the United States has potential CAES sites, as these maps show. Each type of storage has its own advantages and disadvantages. For instance, rock excavation technology is well established, but costly. Solution-mining of salt domes is relatively inexpensive, but salt tends to creep under high temperature. Aquifer storage requires no excavation, but high porosity and permeability are necessary to allow the rapid charging and discharging of a CAES system. Only site-specific studies can determine which options are feasible.

Utilities watching closely

While the Soyland plant pushes ahead, other utilities are paying close attention. Like Soyland, many of these utilities are having difficulty meeting their peak power demands at reasonable cost. Like Soyland, too, they may find pumped hydroelectric inappropriate to their local topography, underground pumped hydroelectric too costly for small-scale peaking operation, and storage batteries too far off. By securing firsthand information on the new CAES plant's progress from Soyland and EPRI, these utilities will be better equipped to make their own generation decisions regarding CAES and will probably be more confident in those decisions. Only this summer a score of interested utilities, the Utility Compressed Air Storage Team (UCAST), converged in Washington, D.C., to trade information and glean advice from EPRI and other CAES experts. UCAST and other communication efforts will make the CAES option available to all utilities.

Just like Soyland, those utilities could

find CAES a cost-effective, fuel-conservative option. The storage scheme applies not only to the hard rock below Illinois but also to the salt domes and aquifers that underlie most of the rest of the country. Perhaps three-fourths of the United States has geologic formations that might host CAES facilities. "Candidate sites are potentially available in just about every major utility service area," remarks Schainker.

If a utility has a need and a prospective site for a CAES plant, it can assemble its facts (such as load factor, cost of other options, and prevailing financial situation) and apply them to one of EPRI's newly developed methods for calculating whether CAES is really the right solution to that utility's particular situation. The Fuel Use Act exemption granted Soyland will doubtless be an added incentive to go with CAES. EPRI research results on CAES systems fired with oil and gas alternatives (such as heavy oil and synthetic oil or gas) also appear favorable, so fuel flexibility will be another incentive. Ongoing research for more

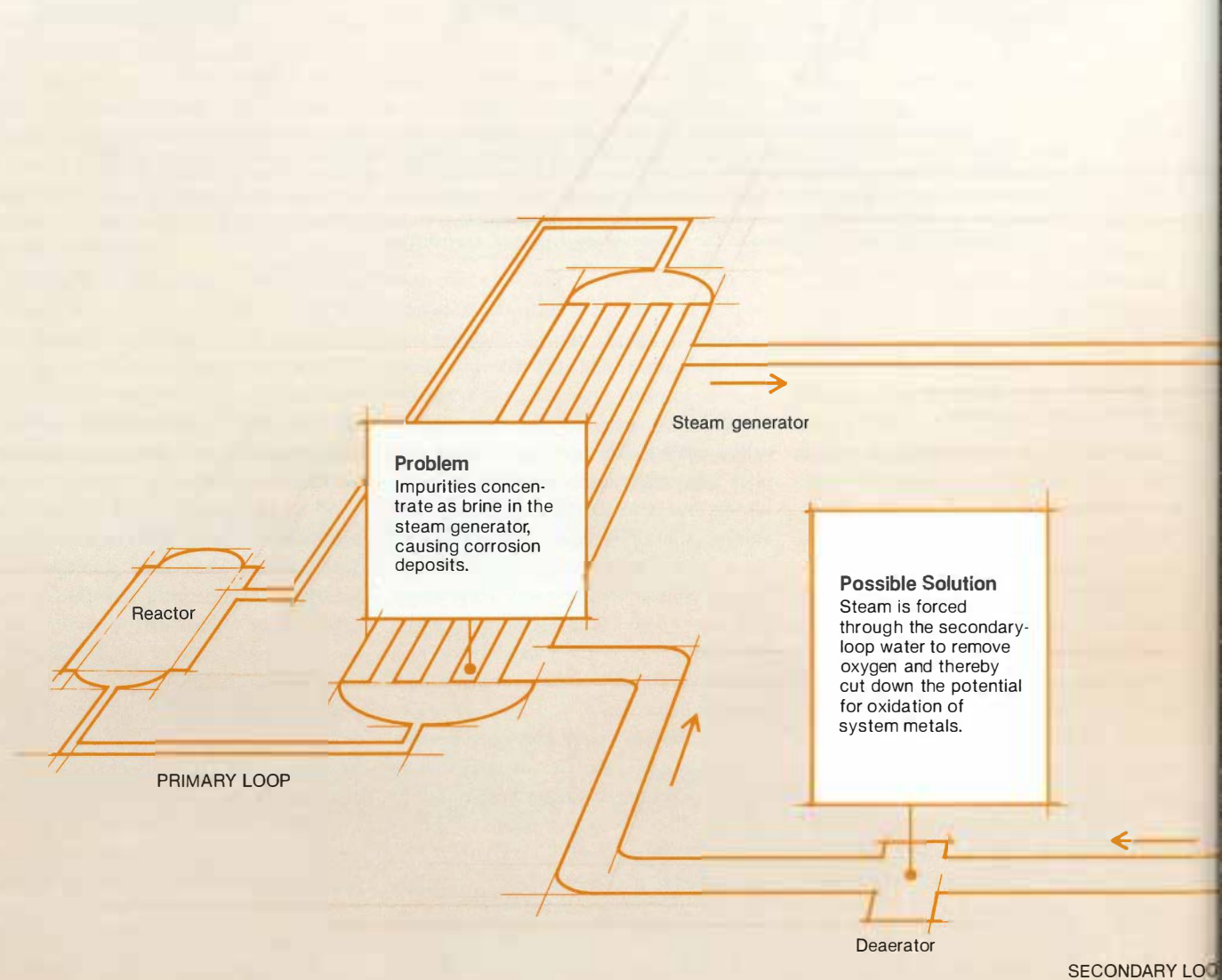
efficient CAES systems (such as those that feature thermal storage) may influence future utility decisions, too.

All in all, there is good reason to be enthusiastic about CAES's chances of becoming a widely used generation alternative. "CAES could account for perhaps half of the industry's energy storage by the year 2020, about 25,000 MW," says Schainker. He estimates CAES's generating potential in the United States over the next 20 years to be between 1000 and 10,000 MW. Right now, many utilities are waiting on the sidelines. They may not be ready to commit to a new peaking or intermediate plant just yet. But they are attentively watching the Soyland experience. By the time the new plant comes on-line in 1986, with all 220 MW being unleashed at each daily peak, other utilities may also have chosen CAES as their best bet. ■

This article was written by Nadine Lihach. Technical background information was provided by Robert Schainker, Energy Management and Utilization Division.

Steam Purity in PWRs

Fine-tuning the chemistry of water and steam is one way of avoiding corrosion damage in the secondary loop of pressurized water reactors (PWRs). Studies of three plants reveal the difference that steam purity can make.



Impurities enter the secondary loop of the PWR through both makeup water from lake or well and cooling-water leaks in the condenser. These impurities can be carried to the steam generator, where they cause corrosion deposits to form. Corrosion products in steam are swept further through the system and become concentrated at the point in the low-pressure turbine where steam begins to condense—the Wilson line. Several plants have effectively reduced impurities, and therefore corrosion, by installing a demineralizer for the makeup water, a resin-bed system to clean condensed steam from the condenser, and a deaerator to remove oxygen from the water and so lower the risk of system metal oxidation.

Possible Solution

Though most condensed steam is drained off, some—carrying concentrated impurities—is swept on with the reheated steam to the low-pressure turbine.

Problem

Impurities concentrate heavily at the point where steam condenses. This transitional zone between dry and wet, usually the third row of blades in the PWR's low-pressure turbine, is called the Wilson line.

Problem

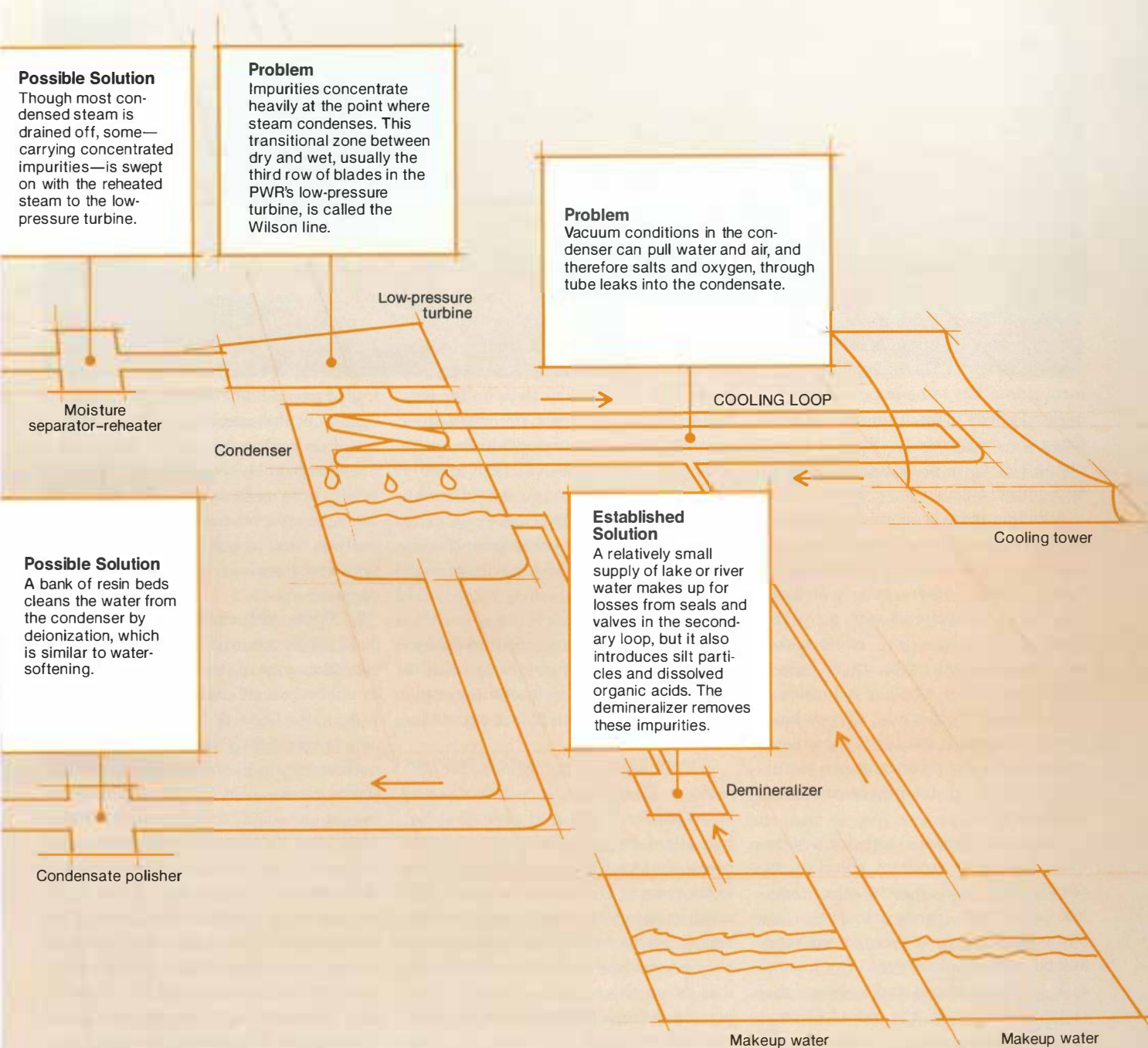
Vacuum conditions in the condenser can pull water and air, and therefore salts and oxygen, through tube leaks into the condensate.

Possible Solution

A bank of resin beds cleans the water from the condenser by deionization, which is similar to water-softening.

Established Solution

A relatively small supply of lake or river water makes up for losses from seals and valves in the secondary loop, but it also introduces silt particles and dissolved organic acids. The demineralizer removes these impurities.



A crack in a power plant turbine usually carries a message—corrosion at work. Corrosion of turbine rotors, disks, and blades results from trace acid or caustic impurities contained in turbine steam. When combined with the stresses from steam traveling at up to supersonic speeds and of centrifugal forces on these large masses rotating at 1800 rpm, corrosion can bring about a phenomenon known as stress corrosion cracking.

Materials vulnerability

Turbine cracks a few millimeters deep can be dealt with by mechanically grinding down the metal surface until the cracks disappear. But larger cracks that weaken the structure of turbine components demand expensive replacement of parts, coupled with an extended plant shutdown. Shutdown can last up to six months, and replacement of an entire rotor costs about \$10 million. If replacement power has to be imported from an oil-fired power plant during a PWR shutdown, the net increase in the cost of supplying electricity to customers could be \$0.5 million a day.

Avoiding these economic burdens entails protecting the turbines. Some utility experts advocate making turbines of tougher alloys; others believe in coating turbine components with corrosion-resistant substances like Teflon, nickel, or aluminum. Both methods can help to some extent. But whether a turbine is manufactured from a new alloy or has a special coating, it is still vulnerable to attack from system-concentrated impurities, even though the mix of corrodents is different.

These corrodents, which include sodium hydroxide, sodium chloride, sodium sulfate, and up to 90 other chemical compounds, precipitate out of the steam and settle in crevices on the rotor, at joints formed where the blades join the disk, or around bolts and keyways that fasten the disk to the rotor. Thomas Passell, project manager in the Chemistry, Radiation, and Monitoring Program

of EPRI's Nuclear Power Division, draws an everyday parallel: "All the common metals we use, that is, those that are relatively inexpensive, are protected by a very thin, stable oxide layer on their surfaces that is formed by a reaction with the oxygen in the air. But that layer can easily break down when salts are present." Passell cites the example of car exteriors damaged by exposure to seawater or to the salt sprayed on snowbound roads in winter. The combination of oxygen, moisture, and salt inevitably starts the process of corrosion.

Two EPRI studies of PWRs show the same correlation—impure steam triggers decay of turbine metals. Another study concludes the reciprocal—there is clear evidence of a connection between pure, demineralized steam and crack-free operating records for turbines. Having demonstrated this generic relationship, EPRI and its researchers are proceeding on two fronts: to improve steam monitoring and analysis, which are key steps on the way to deciding the most cost-effective degree of steam purity, and to upgrade demineralizing systems, which can then reliably maintain that degree of purity. As Passell points out, "Reliability of these expensive machines can best be protected by maintaining the least-corrosive environment."

The secondary loop

Reliability and its economic benefits apply not only to the turbines but also to the steam generator; both of these costly systems belong to the plant's secondary loop.

A PWR has three piping loops for heat exchange. The primary loop carries heated water (under pressure to prevent steam formation) from the reactor's uranium core to the steam generator and then back to the reactor. The secondary loop cycles another circuit of water outside the primary pipes of the steam generator, picking up their heat and making the steam that drives the turbine generator. After passing through high-pressure and low-pressure turbines, the steam turns to liquid again in the condenser and re-

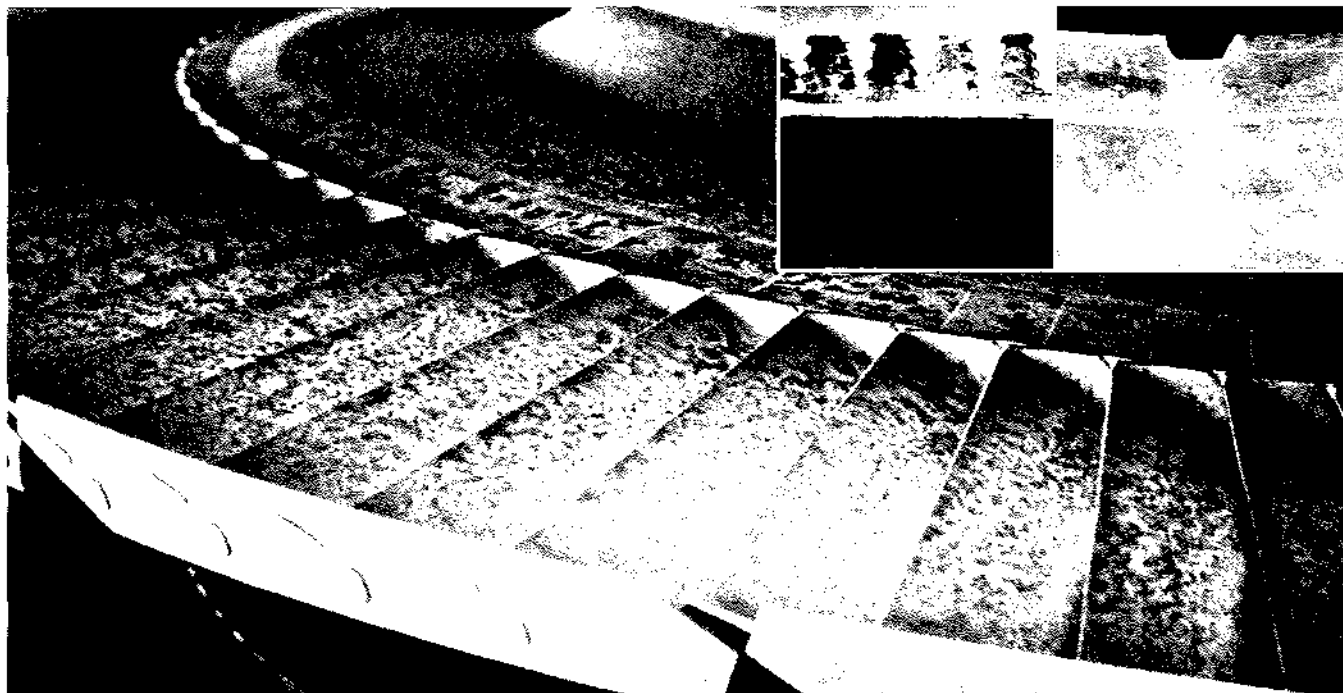
turns to the steam generator. The tertiary loop brings cooling water to the condenser, and this water removes the exhaust steam's heat from tube walls and discharges the heat through a cooling tower or directly into a river, lake, or ocean.

The most common source of impurities is the condenser, where water and air can leak from the thousands of cooling-water tubes into the secondary loop, a problem exacerbated by the vacuum conditions in the steam cycle that tend to draw fluid through leaks. Other sources of impurities are boiler feedwater from inside the loop, which can carry oxide deposits from corrosion in the condenser and feedwater heater chain, and make-up water from outside the loop, which can contain particles (clay, sand, or silt) and dissolved organic substances from river or lake water.

Primary-loop water, because it surrounds the uranium fuel rods, is controlled after demineralization to maintain conditions that preclude corrosion of the fuel rod cladding. Secondary-loop water, however, has only recently been acknowledged as a generic troublemaker that warrants comprehensive monitoring and analysis, and relatively few PWRs as yet control secondary water to a similar degree.

In PWRs, 90% of all cracks in turbine disks have occurred at the dry-to-wet transition zone, dubbed the Wilson line by utility chemical engineers (after Charles Wilson, the Scottish Nobel prize winner who invented the cloud chamber used in nuclear physics). At full operating load, steam enters a PWR low-pressure turbine at about 500°F (260°C) and 200 psi (1380 kPa). As the steam rushes through the turbine, its pressure and temperature drop. At some point, which differs with varying temperatures and pressures, the steam begins to condense, some of it contacting the turbine surfaces, where it proceeds into and out of crevices on the turbine hub and anomalies around blade attachments. This dewpoint area receives the brunt of concentrated acid or caustic

Impurities carried by steam can cause buildup of corrodents at vital points in a PWR's secondary loop, notably in the low-pressure turbine. Pitting corrosion is the chief cause of turbine blade failures in such turbines; attacks on turbine disks can show up as cracks in the disk rim at the blade slots or, especially, as cracks at the disk keyways.



impurities. The concentration phenomenon at the Wilson line occurs in both evaporation and condensation. To use an illustration, the evaporation of a dilute hydrochloric acid solution results in an increased concentration of acid in the liquid phase because the steam removes more water than acid. Correspondingly, at the initial stages of condensation, all the steam has not yet condensed to completely dilute the solution to its original low concentration in the steam.

Every dry-to-wet transition zone in the secondary loop is at risk from trace-impurity corrosion, including, conversely, the final-stage zone of evaporation in the steam generator, which can be compared to a teakettle that boils dry, leaving a concentrated corrosive brine, plus, in the steam generator, an iron-oxide-rich sludge. Some of the salts in the steam generator brine can be picked up by the steam.

Most of the iron oxide tends to remain in the steam generator. Even so, of the 10 million pounds (4.5×10^6 kg) of feedwater that speed through the circuit each

hour, 1–10 parts per billion (by weight) is iron oxide. That proportion is common for a fairly clean system; in a more heavily contaminated system, the proportion could reach 10–20 ppb, translating to about 1 ton per year of iron oxide that travels with the feedwater and deposits in the steam generator. Corrosion products from various sources not only initiate cracking but also can inhibit heat transfer in heat exchangers, cause blocking and denting of tubes, and occlude flow regions because of their porosity.

Impurities in steam

A trace impurity in steam that produces acid conditions (low pH) in condensate is CO_2 , which can originate either directly from the feedwater or via air and water leaks. Acid conditions can be controlled with an all-volatile treatment, which consists of volatile alkaline chemicals, such as ammonia or cyclohexylamine, to alkalinize the feedwater. The chemicals vaporize with the steam and later dissolve in the condensate. Even neutral pH (7 at room temperature, 5.5 at operating tem-

peratures) is a little more corrosive than slightly basic pH, so the alkaline chemicals provide an essential protection to system metals. However, the chemicals must be restricted to certain concentrations where copper or copper-bearing alloys are used in system components, especially when the condensate contains oxygen, as corrosion deposits of copper oxide may form, damaging these components and sending copper into the water to accelerate corrosion in steam generator crevices. The presence of dissolved oxygen, itself considered an impurity because it oxidizes and corrodes metals, is caused by air leakage or inadequate oxygen removal by deaerators in the condenser or feedwater heater train.

More serious from a plant reliability point of view, although less likely to occur, are leaks of primary coolant to the secondary side. The primary coolant contains boric acid and lithium hydroxide as additives. However, the amounts of these additives that have been found in steam generator sludge deposits have

not been more than a few percent. These substances are not considered a serious corrosion risk because the plant would be shut down to fix primary-to-secondary leaks long before chemical damage could be done.

Monitoring impurities and polishing condensate

The level of impurities in steam or water can be determined by a conductivity probe, which measures the total concentration of electrical charge-carrying ions in solution. This conductivity allows an electrochemical reaction between a metal and its surroundings, which then leads to corrosion. Ordinary matter consists of compounds that are electrically neutral because ions normally exist as complementary groups of positively charged cations and negatively charged anions whose charges together add up to zero. For instance, in common table salt, or sodium chloride (NaCl), the sodium cations (Na⁺) are electrically neutralized by chloride anions (Cl⁻). In solution, how-

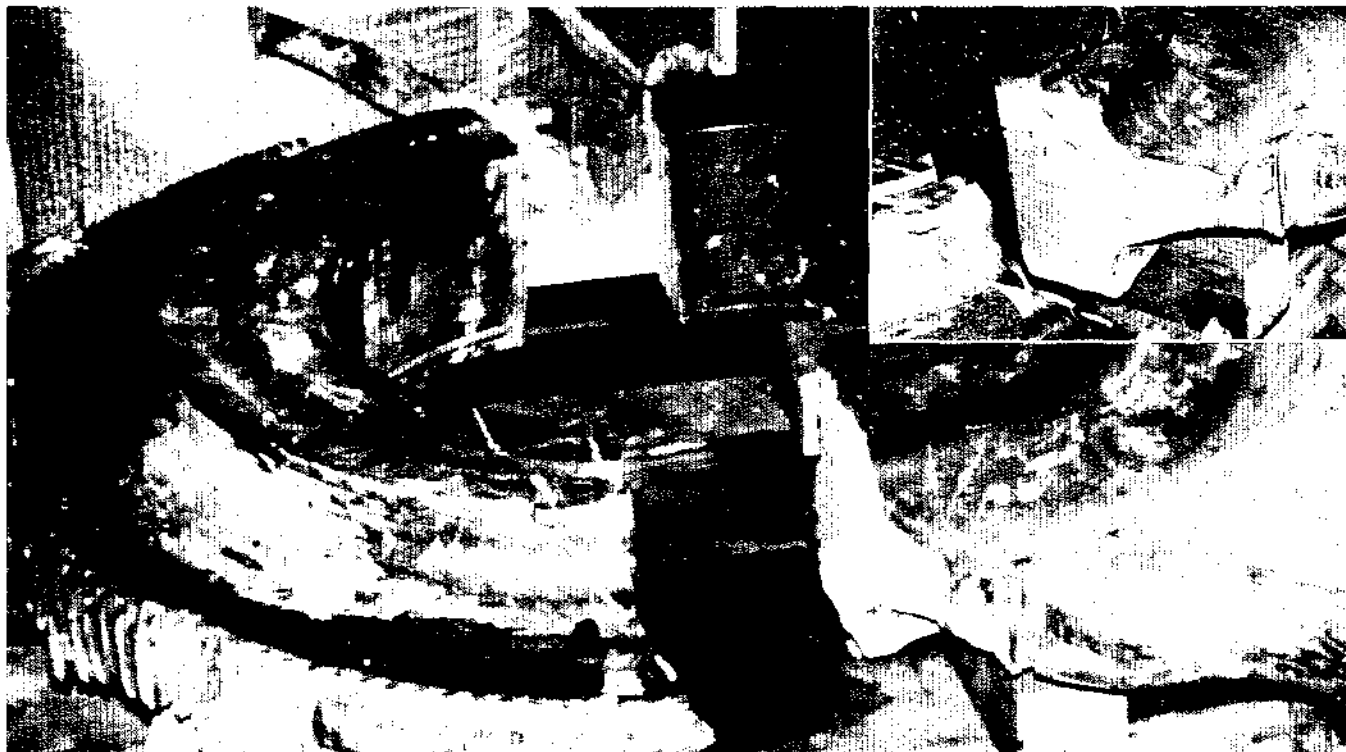
ever, compounds dissociate into their ions; thus, in solution, table salt exists as the free ions Na⁺ and Cl⁻. Substances that dissociate, or ionize, in solution conduct electricity and so are called electrolytes. Likewise, the dissolved impurities in a PWR secondary loop are electrolytes.

Local differences in the same piece of metal or in different sections (e.g., in a turbine) establish an electrical potential difference, which causes an electric current to flow. The area where current leaves the metal and where corrosion occurs is the anode. The place where current enters the metal again and where practically no corrosion occurs is the cathode. Current flows continuously through the liquid and returns via the metal. Local differences in metal may be either chemical or mechanical; for example, they can result from impurities in the metal itself, localized stresses, or scratches and nicks. More likely, though, the potential difference arises because the electrolyte contacting the metal in a crevice is more concentrated than that contacting the metal on

a normal, freely washed surface.

Conductivity probes have a limited usefulness because they only measure total conductivity of all impurity ions present in the steam or water environment. A new instrument that has been tested, the ion chromatograph, registers ion conductivity in such a way as to indicate exactly which impurities are present and in what concentrations. In ion chromatography a sample of condensate is diffused through anion and cation resin beads packed into columns precalibrated to reference standards. Ions in the condensate separate into distinct bands or sections of the column, according to their tendency to stay on the resin.

By comparing their position in the column with the reference standards, the ions can be characterized. The identity of each impurity is represented by the time (usually minutes) that its ions take to desorb from or leave a certain section of the column. The concentration of each impurity is recorded as a conductivity spike on a chart; the more contaminant,



Small corrosion-related cracks in large turbine components can continue to propagate under high-speed operation, leading to catastrophic failure. Here, when cracks in a shrunk-on turbine disk exceeded a critical size, the disk burst into two nearly equal sections.

the larger the spike. When development of the ion chromatograph is complete, it will be possible to finely monitor the steam system environment in power plants and to detect variations in the efficiency of the plants' demineralizing resin beds, or condensate polishers, as they are also called because of their polishing or refining of the condensed steam.

Resin beds, a standard utility installation for cleaning water, are cylindrical tanks, about 10 ft by 8 ft (3 by 2.4 m), tightly packed with resin beads about 0.04 in (1 mm) in diameter. Condensate on its way from the condenser via preheaters to the steam generator flows through these resin beds. In an ion exchange process similar to water softening, positively and negatively charged ions of dissolved impurities attach at ion exchange sites in the resin beads, leaving positive H^+ ions for each cation and negative OH^- ions for each anion. The H^+ and OH^- ions combine to form pure water.

Cleaning or regenerating the resin beds, which is necessary about every two weeks, depending on the amount of contaminants in the system, consists of displacing these ions in the reverse process. The exhausted resin, which can no longer remove ions from the condensate, is backwashed; water is pumped up instead of down through the tanks, loosening and separating the anion from the cation resins by allowing the lighter anion resin to float above the cation. Separation is essential because cation and anion resins must be regenerated differently. Cation resin is treated with sulfuric acid to remove impurity ions, such as sodium, potassium, and ammonium, and to replenish the exchange sites with positive hydrogen ions (H^+). Anion resin is washed with sodium hydroxide to displace negative impurity ions, such as sulfate and chloride, and to replace OH^- ions on all exchange sites.

Proper rinsing of the regenerant chemicals from a newly regenerated bed before placing resin beds in service is as crucial to protection of metals in second-

ary-loop systems as the elimination of impurities.

Experience at three PWRs

The three PWRs whose steam purity has been studied by EPRI have different water treatment systems and correspondingly different turbine and steam generator histories, despite the fact that they came from the same manufacturer.

Arkansas Nuclear-1 (ANO-1) of Arkansas Power & Light Co. has experienced some corrosion deposits in the steam generators and cracking in its low-pressure turbines. Dale Swindle, manager of technical analysis at AP&L, reports that damaged turbine rotors have been repaired or replaced since commercial operation began in 1974. Sludge formed by corrosion deposits in the steam generator is building up and has contributed to operational difficulties. Chemical cleaning by a modified process developed by EPRI is being pursued by the utility, according to Swindle. This cleaning, which may take two to four weeks during a refueling outage, involves two chemical solutions' being flushed through the system separately—one to dissolve iron oxide deposits and the other to dissolve copper oxides.

ANO-1 has demineralizers for condensate polishing, which have been the subject of much investigation. According to Swindle, their performance has been greatly improved in the past two years, compared with their first five years of service. Thomas Baker, technical analysis superintendent at ANO-1, adds that a previous mechanical design problem has now been corrected by adjusting water flow rates through the resin beds and more closely controlling the amount of cation and anion resin in the vessels. The correct resin levels are verified during each regeneration. The polishers serve as chemical filters in the event of a condenser tube leak, which would allow dissolved salts and organic matter from Lake Dardanelle to enter the condensate system.

Implementation of these improved

resin regeneration procedures has allowed ANO-1 to meet the EPRI PWR secondary-water chemistry guidelines. These guidelines include specifications of 3 ppb sodium and 5 ppb chloride in the final feedwater. A Westinghouse Electric Corp. instrumentation assembly that measures pH, oxygen, and conductivity, as well as sodium, continually monitors steam purity.

Specifications for steam purity at Rancho Seco, a PWR in the Sacramento Municipal Utility District in California, are held at 3 ppb of sodium and of chloride and 10 ppb of silica, according to Arshad Alvi, senior chemical engineer with the utility. This means the plant would be shut down if these specifications were exceeded, although Alvi states that Rancho Seco actually operates below those figures—at 1 ppb of sodium and 1 ppb of chloride.

In addition to these precautions, water from the Upper American River is double-demineralized for feed water use, the condensate is deionized in mixed (anion and cation) resin beds, and hydrazine is injected into the secondary loop to reduce oxygen content. In addition, the condenser is made of stainless steel, as opposed to the more common admiralty brass, giving Rancho Seco an exceptionally low number of cooling-water leaks, thereby reducing the risk of impurities. Nevertheless, the plant has been shut down on three occasions because of turbine cracks, two of which were minor and one more extensive. All cracks were located at the Wilson line, indicating that concentrated steam impurities were at least partly to blame.

Turbines at Florida Power Corp.'s PWR, Crystal River Unit 3, have so far shown no signs of cracking since they were installed in 1977, according to plant staff. As an added result of the steam/water purity in the PWR's secondary loop, the steam generator also has been free of corrosion-related leaks. Achieving this clean record came about through rigorous attention to water chemistry.

Well water is the makeup source of

Crystal River's closed-cycle heat-exchange medium, both for nuclear Unit 3 and nearby fossil-fuel-fired Units 1 and 2. The well water is demineralized before use by the fossil units, and Unit 3 was built to tap into this pure water supply, too. But even very clean water contains traces of chemical impurities with concentrations in the parts-per-billion range, and construction contractor Gilbert Associates, Inc., designed Unit 3's secondary loop with even more purification capability: a deaerator to remove oxygen and prevent oxidation of system metals, and full-flow resin beds to demineralize 100% of the secondary-loop water from the condenser.

A unique feature of the resin bed process at Crystal River lies in the replacement of resin beds as opposed to regeneration. The decision to replace the resin began after slightly radioactive water leaked from the primary to the secondary loop, necessitating disposal of the resin bed as low-level radwaste. Plant staff says that total replacement still makes economic sense for Crystal River, quoting 1981 figures of \$458,000 for the cost of new resin, plus \$264,000 for disposal of old resin. The total of \$722,000 for one year stands confidently beside one day's outage cost of over \$500,000—the expenditure to be expected in terms of purchasing electricity from another source in the event of turbine or steam generator failure caused by corrosion cracking. Staff at the utility point out that replacing the resin does not interrupt plant operation; one demineralizer unit at a time is refilled while the others remain on-line.

As well as including a deaerator in the secondary loop to remove oxygen from the steam, Crystal River-3 reduced the concentration of the gas still further by injecting the system with hydrazine, an antioxidant, somewhat antacid substance that forms nitrogen and water from its reaction with oxygen.

Challenges of monitoring steam

"Without comprehensive steam monitoring, we will never be able to fully an-

swer the question, How pure is pure enough to avoid turbine damage?" says Passell. "If we had to guess at a figure, we would say less than 1 part per billion of oxygen and less than 0.1 part per billion of all salts."

Establishing a comprehensive monitoring system in a power plant calls for ingenuity, as can be seen from an EPRI study on monitoring at ANO-1 involving Babcock & Wilcox Co., the manufacturer of the reactor; Nuclear Water and Waste Technology, Inc., the monitoring contractor for the secondary loop; and Westinghouse, manufacturer of the turbines.

An overall project group was assembled that included representatives from NUS Corp., project coordinator and reviewer; Bechtel Group, Inc., architect-engineer for Rancho Seco and ANO-1; L*A/Water Treatment Division, Chromalloy American Corp., condensate polisher system vendor for ANO-1; and Southwest Research Institute, EPRI contractor for a project on failure analysis of turbine materials. These advisers assisted in a complex steam-sampling plan, which entailed six months of installing a number of sampling tubes in the plant while it was still in operation.

Each tube, less than 0.4 in (1 cm) in diameter, took water or steam samples from key points in the secondary loop, for example, the feedwater inlet, the main steam line, the low-pressure turbine, and the moisture separator/reheater (MSR). The MSR removes the liquid droplets from the high-pressure turbine exit steam and heats the dried steam to a superheat of 158°F (70°C) for delivery to the low-pressure turbine. The MSR drain sample was essential, as this area is suspected to be a major source of concentrated impurities in the low-pressure turbine. Measuring steam purity in both the main steam and turbine condensate was also essential, because disagreement between these two purity values can indicate even small leaks in the condenser.

Tubes ranged in length from 1.5 to 500 ft (0.5 to 150 m), and all had a cooler to fully liquify samples containing steam

to avoid loss of the impurities to the sample tube walls. Taking samples from the main steam lines was difficult, but all three contractors succeeded in producing steam impurity analyses. Westinghouse's instrumentation remained at ANO-1, where it is usually in continuous use. The instrumentation panel shows daily readings of impurity levels on chart recorders.

Richard Gillespie, chemical and environmental supervisor at ANO-1, says that if the monitoring system shows that some chemical parameter is exceeding the EPRI guidelines, immediate corrective action is initiated. Typical procedures include checking hydrazine concentration and ammonia feed to ensure that oxygen and pH control is maintained.

Balancing the chemistry in the secondary loop demands constant and costly vigilance, but since the integrity of large systems is at stake, the effort is essential. Protecting turbines, steam generators, and condensers ultimately translates into keeping power plants on-line longer between outages. As Passell points out, "The cost of building plants is so high that it's necessary to match demand by having plants work 70–80% of the time instead of the current average of 55–65%." Focusing attention on steam and water chemistry can ward off cracking and sludge problems caused by corrosion; it can also delay the day that new plant must be built.

Further reading

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Sheldon D. Strauss. "Steam-Loop Reliability Keyed to Condensate." *Power*, Vol. 122, No. 11 (November 1978).

This article was written by Jenny Hopkinson. Technical background information was provided by Thomas Passell, Nuclear Power Division.

The Office of Energy-Related Inventions

Offering assistance to individual inventors and small businesses who have developed energy-saving ideas, the federal government's Office of Energy-Related Inventions helps creative concepts become marketable products.

Complaints of a lack of technical creativity in the nation today can easily be silenced by a walk through the file room of the Office of Energy-Related Inventions (OERI). Stored there is documentation on the 18,000 energy-related inventions submitted to the office since the program began in 1975. The long rows of files are evidence that the individual inventor is alive and well in the United States. And the federal government is doing its best to keep him healthy.

The energy-related inventions program was a result of the Federal Nonnuclear Energy Research and Development Act of 1974, which directed the government to encourage innovation in new energy technologies. DOE, assisted by the National Bureau of Standards (NBS), was given the responsibility of spurring this

innovation. Consequently, OERI was created at NBS to evaluate promising non-nuclear energy-related inventions, particularly those submitted by independent inventors and small companies. There is no fee for submitting an invention. NBS reviews all inventions received and recommends to DOE those that offer the most promising results.

But as Albert Hedrich, chief evaluator at OERI, explains, "Almost half of the inventions we receive fail to qualify for full evaluation. The description of the invention must be clear and concise and should emphasize the uniqueness of the device in producing or conserving energy. In addition, its performance or cost must offer an advantage over similar products currently in use. It also must be technically feasible. We can't accept inventions for perpetual motion machines because they

violate the second law of thermodynamics, yet 10% of all the inventions we receive are based on the concept of perpetual motion."

NBS Evaluation

The strict evaluation process at NBS weeds out those inventions that are technically flawed. Once a submission is found to be complete and acceptable, brief technical opinions are solicited from other government scientists, engineers, consultants, or contractors. These outside opinions on the invention are then reviewed by an OERI staff evaluator, who makes a judgment as to the invention's potential. The items that survive this first scrutiny are considered promising and proceed to a second-stage evaluation. In this stage a more in-depth analysis is conducted and a formal report on the inven-

tion is prepared. The inventions confirmed as having potential after this evaluation are then forwarded to DOE with a recommendation for government support. NBS conducts no testing of the invention—only a written description is submitted.

Hedrich emphasizes that although NBS uses outside consultants, all the decisions regarding an invention are made within the inventions office. He heads up a staff of five evaluators, whose backgrounds cover almost all the engineering disciplines—mechanical, electrical, thermodynamic, and automotive. Hedrich himself reviews every invention that is rejected after the second-stage evaluation. Of the 9000 inventions evaluated since 1975 (out of the 18,000 submitted), NBS has recommended only 219 to DOE.

"We have recommended to DOE on the order of 1.5% of the inventions submitted to NBS, which is a pretty good percentage for a completely open program of this type. DOE ends up giving a grant to almost 90% of the inventions we recommend to them. In many cases," Hedrich notes, "all the inventor really wants is a recommendation from NBS that his project has merit. The inventor can then take this NBS evaluation to a bank and possibly get his own funding. The prestige of an NBS recommendation may give the inventor access to funds way beyond what DOE can offer."

Once an invention is recommended to DOE by NBS, the inventor is asked to submit a preliminary proposal that emphasizes the support he needs to continue on with his work. The DOE staff will decide if the proposal's method of developing the invention is technically valid and if the costs are reasonable and in proportion to the benefits. DOE offers one-time assistance, usually in the form of a grant award of, on the average, \$80,000, although some awards have exceeded \$100,000.

"There is a big advantage to separating



Hedrich

the evaluation and funding functions," Hedrich says. "We restrict ourselves to making a technical judgment of the invention but don't recommend the amount of money an inventor should receive. That is the role of DOE. However, we may recommend what we feel the next step should be for an invention—for example, whether it needs more research, whether it is ready to be field-tested, or whether a market survey needs to be performed to see if there is any demand for the product."

Hedrich cites the example of an inventor in Seattle, Washington, who designed a device that extracts waste heat from the hot ingots in small steel foundries and then uses the waste heat to preheat scrap steel prior to placing it in an electric-arc furnace. Before DOE committed to develop the device, a market survey was performed to determine if small foundries would actually save energy by its use. The survey showed that a 20% energy savings was possible, and as a result, many steel companies expressed interest in the process. The inventor was given a

\$170,000 DOE grant and has now obtained a loan from the Small Business Administration to assist in the commercialization of the process.

This particular device was one of the inventions in the category of industrial processes, the subject area with the highest success rate for submitted inventions. Some of the other major NBS categories are fossil fuel systems, direct solar applications, transportation systems, building structures, and components of combustion engines. The industrial process category has the highest funding success rate because the inventors who develop these devices usually work in the industrial arena and know how to apply their devices in a specific industry. Inventions with the least success in receiving funding recommendations from the NBS are automotive-related.

"The automotive industry is very mature, and the chances are pretty small that an inventor will come up with a new internal combustion engine by working in his basement," Hedrich notes. "In the first place it is an extremely expensive technology; General Motors, for example, spent millions trying to perfect the Wankel engine and then scrapped it. But many people dream of creating a car that gets 75 miles to the gallon and then retiring on their royalties. The inventions with the highest rejection rate are attempts to improve the internal combustion engine."

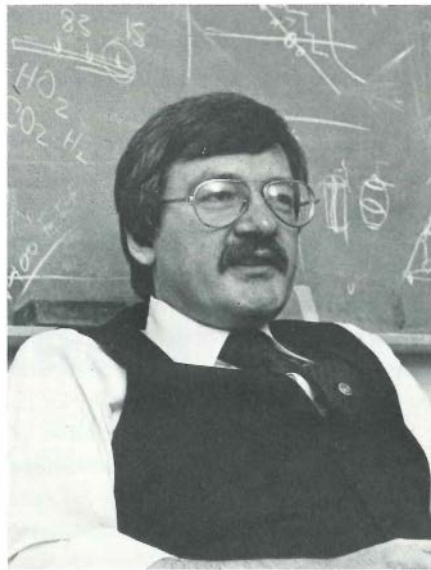
Many inventors find it hard to take no for an answer. They may show up at the NBS offices, sometimes with invention in hand, to argue with the evaluators about why their invention was not recommended. In some extreme cases, they even call their congressman with a grievance against the NBS. Because of the stringent evaluation system at NBS, however, these irate inventors have little luck with their complaints. NBS can always technically substantiate why the invention failed to receive a recommendation.

But in order not to discourage the serious inventors, OERI also maintains an open appeal system. An inventor can re-submit his invention to the office for technical review as many times as he pleases. "In fact," Hedrich states, "we encourage the inventor to come back and convince us that his product will work. We feel that one of the most valuable aspects of our program is the information we give an inventor when his invention is rejected. We consider this program to be an educational process; if the inventor listens to us, he can probably save a lot of time, trouble, and money." In fact, of the over 200 inventions NBS has recommended to DOE, almost 12% had been rejected by the office at least once.

Launching Innovation

When an invention survives the NBS evaluation process and is recommended to DOE, the DOE invention coordinators take over. A staff of four technical coordinators work closely with the inventor to determine the next reasonable step for the invention and how much money it will take to reach that step. Randall Stephens, director of the Small-Scale Technology Branch at DOE and head of the invention group, explains that DOE is funding inventions that are in their last stages of R&D. "On the average, an inventor will invest approximately \$50,000 of his own money, or that of family and friends, in his invention. Those who come to our program have usually run out of this personal source of capital and have not yet developed their invention to the point of marketability. The energy-related inventions program fills the gap between their own financing and the point where the invention is ready to enter the commercial market."

An excellent example of this push into commercialization that DOE provides is a process that recovers waste aluminum from the dross. The inventor collects the



Stephens

dross material from aluminum plants, separates out the usable aluminum at his own production facility, and resells it. DOE awarded the inventor a grant of \$158,000 in 1981 to develop and design a practical and economic production facility, which provided the needed capital to start up production. Stephens reports that the inventor is now earning approximately \$25 million a year from this process.

Another example of particularly successful inventions that are also succeeding commercially is a nonmetallic flat plate solar collector.

Charles Edwards of Chelmsford, Massachusetts, developed the solar hot water heating system, which consists of a solar collector made from ethylene-propylene-diene monomer, a synthetic rubber compound. This synthetic material makes the collector much cheaper to produce than the normal metallic type. The collector is also impervious to severe changes in the environment. Edwards received a \$99,999 grant from DOE to continue development and commercialization of the solar collector. "The NBS-DOE grant helped

us enormously," he says. "We would not be at our present stage of technical development without their support." Prototypes of the solar collector are currently being tested on residences in New Hampshire and Massachusetts, and once the testing is complete, Edwards will commercially market the collector through his own company.

Idea Broker

These success stories clearly demonstrate application of DOE's award money. Stephens believes, however, that DOE's role should go beyond awarding grants to inventors. He would like to get more money from the private sector involved in the program, with DOE acting as a broker to bring together the inventor and private funding sources. "Since I took over the program nine months ago, I have been trying to get more in touch with the investment community to tell them about the program.

"Venture capitalists, bankers, and businesses looking for limited R&D partnerships are interested in the inventions that have come through the NBS evaluation process because they know that NBS only recommends inventions that are technically feasible. This kind of partnership could also be a life saver for the inventors, many of whom have excellent technical skills but little knowledge of what it takes to get a product into the market; inventing and marketing are two completely different sets of talents," Stephens explains. "Our role would be to work closely with both investor and inventor to be certain that both gained from the relationship."

Finding private sector funding has also been important to Stephens because there may not be federal funding available for energy-related inventions next year—the current budget proposal for FY83 does not include money for the program. However, there is support within Congress—the House Science and Technology Com-

mittee has recommended \$4.5 million for the program, which is not far from the \$5.2 million it received for FY82.

Stephens emphasizes that even if funding is restored, the program will still be concerned with finding financing from private sources. Since most new jobs are created from the startup of new businesses, Stephens believes that the support of individual inventors and small businesses can help the country get back on its feet economically. "Innovation and productivity are now major national concerns. Small companies can afford to be more flexible and take larger risks than large corporations, which is why most new products and processes come out of small, independent businesses, particularly in the high-technology area. But too often these independent inventors fail because of a lack of capital or business

sense. What the federal government should do through programs like OERI is hook up these new ideas with money available from private investors."

One way that the energy-related inventions program is already bringing together inventors and entrepreneurs is through a series of regional National Innovation Workshops. The workshops give inventors practical guidance and information on patent law, licensing and selling an invention, and developing and marketing a product. Sponsored by DOE, NBS, and the American Association of Engineering Societies, the workshops also make information available on consulting services and financial assistance from both public and private sources. One major problem that all inventors face is keeping up with the state of the art of new products and designs, and many

inventions are rejected by NBS because they duplicate another product already patented or even in the marketplace. To address this problem, the workshops discuss ways to access new technical and business data.

Stephens also points out that "these workshops provide would-be inventors with a vision of the whole process they will have to undertake to turn their ideas into reality. Those who understand all that is involved and still go ahead and pursue their ideas will be the ones to succeed. And we hope that the energy-related inventions program can help them reach their goal." ■

This article was written by Christine Lawrence, Washington Office.

EPRI Offers Telephone Information Service

EPRI's Technical Information Center can provide fast answers to technical inquiries.

A telephone information service to assist people who are looking for information about EPRI activities and research is operated by the Technical Information Division. This service, which can be reached by dialing (415) 855-2411, is designed to provide quick answers to questions about current EPRI R&D results and about other R&D programs in the utility industry.

Dialing the information number puts the caller in touch with information specialists who will answer specific technical questions on EPRI research projects and assist in searching the Electric Power Database (EPD) on a large computer. The service can also refer callers to appropriate EPRI project managers, provide information on EPRI-sponsored workshops and seminars, direct callers to specific EPRI publications, connect them to the order desk at the Research Reports Center, provide information on the expected publication date of forthcoming EPRI publications, and forward mailing list changes to the correct EPRI staff member.

The EPD maintained by the Technical

Information Center is one of the few technical reference systems in the world on active research and can be accessed online through the DOE/RECON information retrieval system or through DIALOG Information Services, Inc. The EPD contains over 9000 R&D projects—over 4000 EPRI-sponsored projects and about 5000 projects supported by more than 100 utilities concerned with electric power development.

The projects are indexed under seven broad categories: advanced power systems, fossil fuels, nuclear power, transmission and distribution, customer use, economic aspects of energy systems, and environmental assessment. Indexing of records by subject permits the user to review quickly all projects under general or specific topics. The data base is further indexed by corporate names, funding levels, dates, and contract and report numbers.

Each project record is clear and informative, and it provides the contacts and publications necessary to carry an inquiry further. The data base can be used as a

reference system in itself or be coupled with EPRI's printed information publications. Monthly updates of the data base are provided to keep the industry apprised of new projects.

Another useful information source from the Technical Information Division is the *Digest of Research in the Electric Utility Industry*. The three-volume 1982 edition, now available, is a printed record of the R&D projects in the EPD as of August 1982. Volume 1 of the *Digest* contains records of research completed from 1973 through 1980, Volume 2 describes ongoing research to the present time, and Volume 3 offers expanded subject and corporate sponsor indexes to Volumes 1 and 2. Since the research recorded in Volume 1 has been completed, that volume will not be revised. Volumes 2 and 3, however, will be updated and printed annually.

To receive a copy of the *Digest*, for information on access to the EPD, or to get answers to specific technical questions quickly, contact the EPRI Technical Information Center. ■

Starr Addresses Uranium Institute

The expanded use of uranium for power production is essential to provide a substantial portion of the electricity necessary for world economic growth, stated EPRI Vice Chairman Chauncey Starr at the Seventh Annual Symposium of The Uranium Institute held in London last month. Starr was the keynote speaker at the symposium, which brought together representatives from over 50 major industrial and commercial organizations involved in nuclear power operations—uranium mining, reactor operation, and the associated fuel cycle services.

In his address, Starr stressed that electricity historically has been the key energy form and thus a predominant factor in industrial growth; and with fossil fuel sources either diminishing or becoming increasingly costly, uranium will play a major role in electricity generation for the future. The world, he emphasized, really does not have the choice of doing without it. "We are left with uranium as the only major source of electricity available to fill the needs that we foresee, and these needs are real." Starr cautioned that if public doubts concerning nuclear power do not soon diminish, development of a much needed long-term energy source may be seriously hindered.

By all the evidence, uranium is also going to be the most economic source of electricity, Starr added, although it is mainly available to nations with large capital resources. Coal plants, which can be built in smaller sizes, and oil and gas plants are the small users' choice. "If the industrial nations wish to help the developing world, they should build uranium power plants, so as to make fossil fuels more available and less costly for the small users," he stated.

With uranium taking on increased importance in the global energy mix, the

concern becomes one of management. "The obstacles to this expansion," Starr said, "arise not from the technology but rather from the inadequacies of our industrial, political, and economic institutions to effectively manage this new energy system nationally and internationally."

The management of nuclear power, from concept and construction to daily operation, requires organizations specifically tailored to this technology. Starr compared its managerial needs to those of large-scale programs for space satellites and said that only "multinational or international management of the fuel cycle plants could provide security of supply and assurance of dedication to peaceful purposes." He predicted the issue will become more pressing as more of the developing countries obtain uranium-fueled power plants.

"If internationalizing the fuel cycle is ultimately desirable—and I believe it is—the time window for doing so exists in this decade, but it may start closing thereafter," Starr said. "The special role of uranium for power production requires that the industrial nations thoughtfully plan and establish unique institutions and management to meet the demands of this inevitable, necessary energy source." ■

Acid Deposition Study Expanded

A five-year study to learn why lakes become acidified is being extended by three or four years and expanded to include 20 more lakes in the Adirondack Mountains in upstate New York. The expanded Adirondacks study will develop a methodology for assessing the acidification susceptibility of lakes in an entire region. Plans are also under way to begin similar studies in Wisconsin and the southern Appalachians.

Since 1978, the research has focused on three lakes in the Adirondacks. The lakes

are within 20 km of each other and receive the same precipitation. Yet one of the lakes is acidic, another shows substantial swings in acidity, and the third is neutral. So far the study has produced data indicating that the type of bedrock in the watershed is not the only determining factor in lake acidification. "We have learned that we cannot look just at the relationship between the precipitation and the lake water but must consider the processes going on in the surrounding terrestrial system as well. They have as much or more influence on acidity," explains Robert Goldstein, manager of the integrated lake-watershed acidification study at EPRI. For example, acid rain and snow apparently can be neutralized by minerals in the soil around the lake.

The additional studies to be conducted in Wisconsin and the southern Appalachians will attempt to discover differences in acid deposition in relation to different environments. Lakes in both regions are believed by some to be vulnerable to acidification, although no acidic lakes have been reported. In Wisconsin the lakes are fed only by groundwaters, and in the southern Appalachians the lakes are much larger and the soil is much older than in the Adirondacks.

In a related study, the Ecological Studies Program has produced a new evaluation of the feasibility and effectiveness of liming to diminish surface water acidification. The evaluation is part of a project to develop background information for planning future research on the use of liming in fishery management.

The report of the project findings (EA-2362) summarizes information obtained from a review of the literature on the subject, as well as from visits to fisheries that use liming in the management of acidic lakes in Scandinavia, Canada, and the United States. The report covers two major areas: liming application techniques and materials; and physical, chem-

ical, and biological responses of lakes to liming.

According to the EPRI Program Manager Robert W. Brocksen, several issues require further study: long-term pH management strategies; effects of pulses of acidic water into lime-buffered lakes; and the effects of liming on the carbon cycle, the phosphorus cycle, and other vital nutrient cycles.

The broad ecological ramifications of liming are also of interest. Future research will appraise liming as a means of diminishing surface water acidification and, to a lesser extent, the acidification of terrestrial ecosystems.

Brocksen notes that "efforts to counter the effects of soil and water acidification by adding alkaline materials are not new. However, data on the quantities of liming

materials in past projects are difficult to use as a basis for deriving average resource requirements.

"The addition of any of a variety of calcium-based alkaline compounds to diminish surface water acidification will cause physical, chemical, and biological changes. Therefore, fishery managers should give close attention to their choice of alkaline compounds." ■

CALENDAR

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

OCTOBER

12-13

Workshop: Evaluation of Small-Hydro Sites
Chicago, Illinois
Contact: Charles Sullivan (415) 855-8948

13-14

Seminar: Cathodic Protection of Bare Copper Neutral Conductors on URD Cables
Arlington, Virginia
Contact: Thomas Kendrew (415) 855-2317

13-15

Transmission Line Grounding
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

13-15

Seminar: Fuel Supply
St. Louis, Missouri
Contact: Jeremy Platt (415) 855-2628

14

Over/Under Capacity Planning Model, Update and Enhancement
Chicago, Illinois
Contact: Hung-po Chao (415) 855-2622

14-15

Seminar: Cooling Lake Multiple-Use Assessment
Chicago, Illinois
Contact: Robert Kawatani (415) 855-2969

17-22

Decision Analysis for Utility Fuel Planning and Management
Minneapolis, Minnesota
Contact: Stephen Chapel (415) 855-2608

18-20

Substation Grounding
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

25-26

Seminar: Turbine Missile Effects in Nuclear Power Plants
Palo Alto, California
Contact: George Sliter (415) 855-2081

25-27

7th International Conference on Fluidized-Bed Combustion
Philadelphia, Pennsylvania
Contact: Shelton Ehrlich (415) 855-2444

26-28

Seminar: Polynuclear Aromatic Hydrocarbons
Columbus, Ohio
Contact: Jacques Guertin (415) 855-2018

27-28

11th Semiannual Meeting: ARMP Users Group
Omaha, Nebraska
Contact: Walter Eich (415) 855-2090

NOVEMBER

1-4

1982 Joint Symposium on Stationary Combustion NO_x Control
Dallas, Texas
Contact: Michael McElroy (415) 855-2471

2-4

Workshop: Hydro Operation and Maintenance
Atlanta, Georgia
Contact: Charles Sullivan (415) 855-8948

11-12

Seminar: Cooling Lake Multiple-Use Assessment
Houston, Texas
Contact: Robert Kawatani (415) 855-2969

11-12

Water Quality Management, Hydroelectric Power Discharges
Orlando, Florida
Contact: Charles Sullivan (415) 855-8948

14-18

National Seminar: Fuel Cell
Newport Beach, California
Contact: Edward Gillis (415) 855-2542

17-18

2d EPRI Workshop on Water Supply for Electric Energy
Palo Alto, California
Contact: Edward Altouney (415) 855-2626

17-18

Innovative Approaches to Utility System Planning: Modeling Tools
Washington, D.C.
Contact: Virginia Donaldson (415) 855-2746

DECEMBER

15-17

4th Symposium on Electric Utility Load Forecasting
Dallas, Texas
Contact: Larry Williams (415) 855-2415

R&D Status Report

ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Director

ADVANCED COOLING OF UTILITY GAS TURBINE ENGINE COMPONENTS

The major improvement utilities desire for combustion turbine power plants is increased reliability. To assist in such an improvement, EPRI embarked on the high-reliability gas turbine project (RP1187). The utilities also have the goal of lowering the heat rate and the cost of electricity. For combustion turbine-combined-cycle plants, this can be accomplished by raising the turbine inlet temperature. However, in the past an increase in turbine inlet temperature has unfortunately been associated with a decrease in reliability and durability, especially as metal temperatures have risen. It is the purpose of another project, therefore, to apply advanced cooling and fabrication techniques to the engine hot section in order to lower metal temperatures, while permitting increases in turbine inlet temperatures to the competitive levels expected in the mid and late 1980s (RP1319).

Phase 1 of RP1319 involved the preliminary design and analysis of advanced cooling components, together with conceptual design and performance analysis of the engines and power plants using these components. There were four Phase 1 contracts.

□ General Electric Co. investigated the use of a water-cooled first-stage turbine stator nozzle (RP1319-1).

□ Westinghouse Electric Corp. and General Motors Corp., Detroit Diesel Allison Division (DDA), investigated the use of skin-spar construction of the turbine blades and vanes (RP1319-2).

□ United Technologies Corp. investigated the use of wafer and bonded construction of the turbine blades and vanes (RP1319-3).

□ Westinghouse and DDA investigated the application of Lamilly impingement—full-film cooling to the combustion liner (RP1319-4).

Phase 2 encompasses the detailed design, fabrication, and acceptability tests of some

of these advanced cooling components. There are currently three Phase 2 contracts.

One contract in Phase 2 is with Westinghouse (using DDA as its major subcontractor) and involves the application to utility combustion turbine blading of the advanced skin-spar fabrication and cooling techniques developed by DDA for advanced aircraft application (RP1319-5). In Phase 1 a number of variations of the skin-spar technique were preliminarily designed. The chosen concept, shell-spar, has an airfoil-shaped spar with cooling slots cast into the outer surface and cooling plenums cast into its center. This is wrapped by an alloy shell over the cooling slots to form the airfoil surface. The cooling slots are mainly in the chord direction with short spar segments that act as manifolds connecting each pair of slots (Figure 1). The cooling air enters the blading through the first and third cavities (Figure 2) and proceeds through entry holes drilled in the spar

to the cooling slot manifolds. The cooling air moves along the slots and cools the shell material. It then passes through drilled exit holes and back into the center cavity, except for the trailing edge slots, where the cooling air exits directly out the trailing edge. This cooling technique permits the cooling air to be right under the surface with a high cooling effectiveness. It provides a low metal temperature with reduced surface temperature variation and thus a very low requirement for cooling air. Similarly, this cooling method permits the separate choice of shell and spar alloys with the optimal properties of each function.

Inconel 617, the shell alloy, was chosen mainly for its high-temperature corrosion resistance because it does not have to carry the structural stress. The spar material, which is kept below 750°C (1400°F), does not need to have strength at the very high temperatures (850°C, 1600°F) reached by

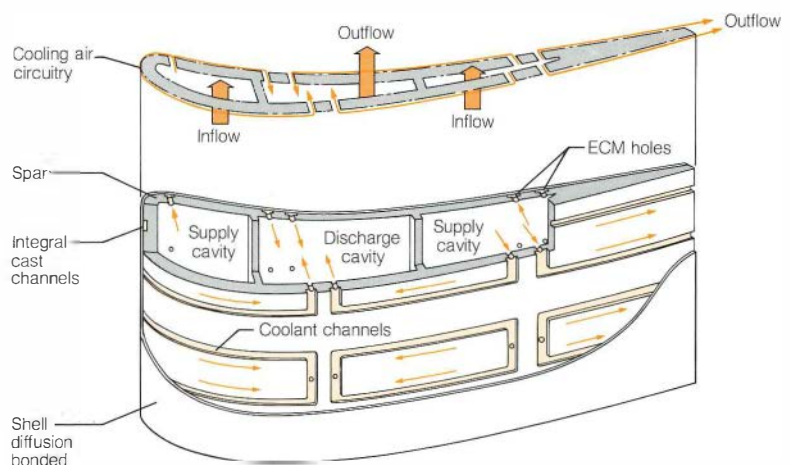


Figure 1 Unwrapped shell-spar blade design, showing the cooling channels connected by electrochemically machined (ECM) holes to the supply and discharge cavities.

Figure 2 Cutaway of shell-spar blade design, showing coolant flow cavities.

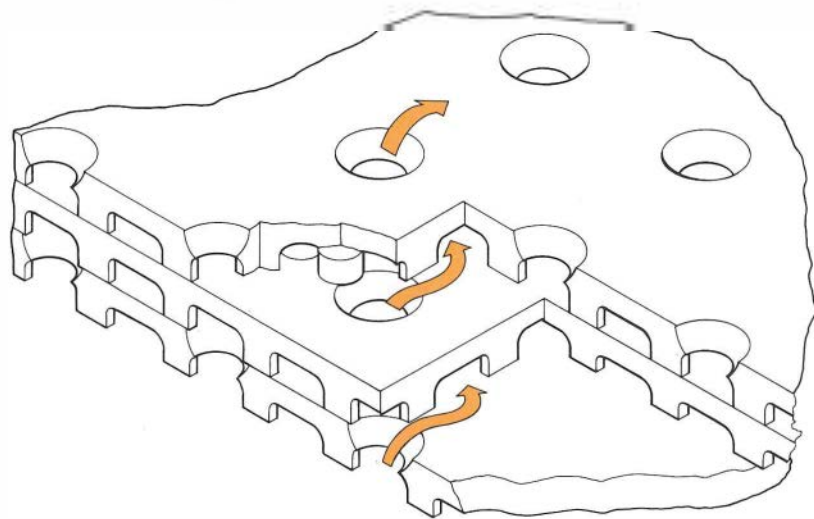
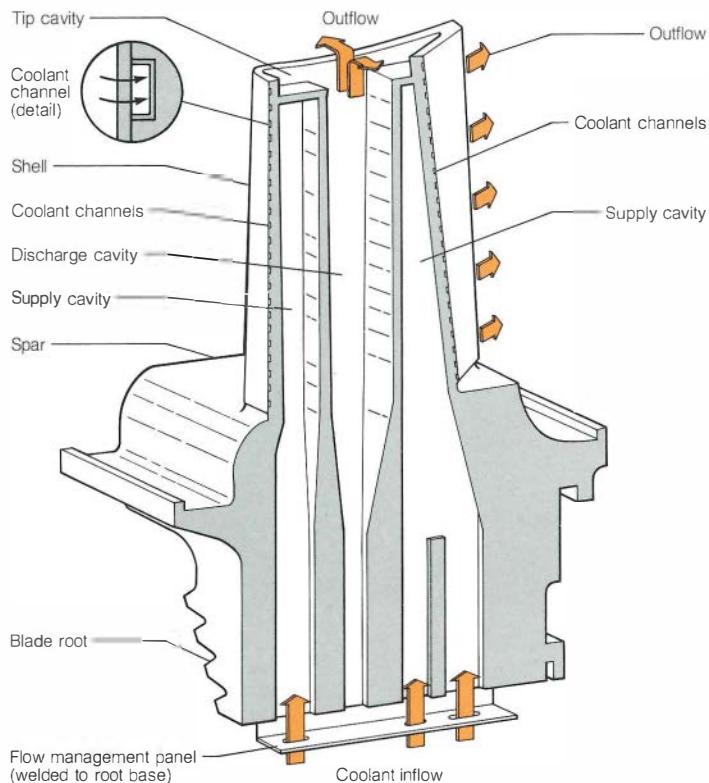


Figure 3 Cutaway of Lamilloy lining, showing the cooling-air path from the outside through to the inside hot surface.

ordinary blading. So Inconel 738 was the alloy chosen for the spar; it is also corrosion resistant, castable, and very strong at intermediate temperatures.

Heat transfer experiments on the slot cooling have been performed. The test results pointed up the importance of free-stream turbulence, the slot entrance region, and the metal temperature gradient effect on the heat transfer rate, which previously had been ignored in design calculations. These effects have now been incorporated into the design process. The revised turbine blade design is now virtually complete. The stator vane design has not yet been completed.

Fabrication development has been proceeding. Successful fabrication of test elements simulating stator vanes has been made by hot isostatic pressing of the shell onto a cast spar. When the stator vane design is finished, a complete engine set plus spares will be fabricated. The vanes will be put through a number of nondestructive evaluation (NDE) procedures, followed by complete destructive evaluation of some of the vanes in order to check the NDE procedures. The major evaluation criteria are completeness of the shell-to-spar bond; uniformity of the cooling-slot passages; cooling flow rate per internal pressure drop; and overall dimensional fit of the blading. There will also be a heat transfer test of the stators in a combustion tunnel sector to verify the design heat transfer analysis under the most realistic conditions obtainable outside an actual engine.

The projected plan is to place the shell-spar blading in the prototype of the W251-B10, an advanced 40-MW utility gas turbine engine, replacing the standard blading. This modified engine is to be highly instrumented and run for a year at a utility site, thus providing a demonstration of the temperature capability and prospective durability of the shell-spar blading.

The second project in Phase 2 is also with Westinghouse and DDA (RP1319-7). This project is for the application of the Lamilloy fabrication and cooling technology to a utility combustion turbine combustor. Currently, the combustors are usually cooled by film cooling air introduced at discrete stations along the combustor. This leads to high thermal gradients near the cooling-air entry locations.

The Lamilloy material consists of three sheet layers, separated by pedestals, that have been etched to form many small holes, allowing the cooling air to follow a labyrinth from the outside, through the sheets, and out the inside holes (Figure 3). This provides cooling by a combination of the impinge-

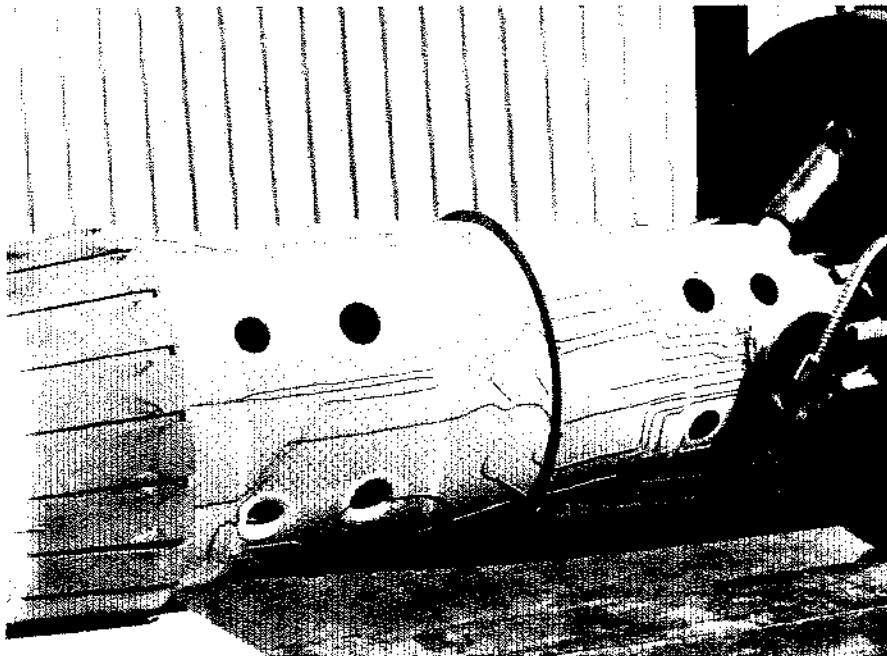
ment, convection, and transportation mechanisms. The cooling is quite uniform, and the thermal gradient is very low over the surface of the Lamilloy. Also, much less cooling air is needed with Lamilloy, which allows more secondary air to be available for dilution downstream. This can improve the temperature pattern factor at the combustor exit, which has a beneficial effect on the cooling of the turbine blading.

Fuels that have a low hydrogen content, such as some residual petroleum oils and coal-derived liquid fuels, tend to transfer high flame radiative heat to the combustor liner. The Lamilloy combustor liner has been designed for a 9% hydrogen fuel and to have a design life of 100,000 hours, based on stress rupture. With standard No. 2 gas turbine distillate oil containing 13% hydrogen, there is much less flame radiation, the wall temperatures are lower, and the design life is even longer. (This is not to claim there are no effects other than stress rupture in the combustor liner that could cause the combustor to fail earlier.)

One Lamilloy combustor liner has been designed and fabricated. The liner has been designed to be directly refittable into a Westinghouse 501B utility combustion turbine engine. The fabrication was carried out by DDA with a shop-level fabrication that introduced more weld joints than would be necessary in a series production type of construction. The Lamilloy combustor liner has been tested in the Westinghouse combustion test facility, which closely simulates the overall combustor layout and engine air flows.

The combustor has been tested with two test fuels: 13.0% hydrogen content, No. 2 gas turbine petroleum distillate oil, and 8.7% hydrogen coal-derived liquid fuel. The liner temperatures on the outer surface were thoroughly measured with thermocouples, while both the inner and outer surface temperatures were evaluated with thermal paint (Figure 4). The temperature distribution over the Lamil-

Figure 4 Lamilloy combustor liner shown after the test with thermocouple wiring and shading (thermal paint) that represents temperature variation.



loy surface was reasonably close to the design estimation. However, the measured temperatures were higher than designed at the weld joints, the air scoops for the dilution air, and the uncooled aft section. These areas have yet to be evaluated for durability from the aspect of low-cycle fatigue.

The third current project in Phase 2 is with General Electric and was started in July 1982 (RP1319-10). The objective of the project is to develop an actively cooled transition piece. The transition piece forms the section of the hot gas path between the cylindrical combustor liners and the annular first-stage stators of the turbine. In utility turbine designs, the combustion system is termed reverse flow. The relatively cool compressor exit air bathes the outside of the transition piece and the combustor before entering the

combustor to be burned. This bath has provided adequate cooling of the transition piece when the hot combustion gases flowing inside were below 1100°C (2000°F). But in current designs—with combustor exit temperatures of 1150°C (2100°F) and with plans for 1250°C (2300°F)—the transition piece faces thermal distress.

The advanced transition piece cooling design will use active impingement cooling. An outside sleeve with many holes will force the compressor exit air to impinge on the inner transition piece and flow backward along its exterior. This design, which has not previously been used, is expected to lower metal temperatures by approximately 100°C (200°F) and allow a transition piece life greater than 50,000 hours. *Project Manager: Arthur Cohn*

R&D Status Report

COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Director

COOLING-TOWER R&D

Cooling-tower R&D is part of a broad waste heat management and utilization activity within the Institute. The work is carried out across three technical divisions and spans the areas of power plant cooling systems, environmental effects, and resource utilization. This article deals with power plant cooling systems, which are the responsibility of the Coal Combustion Systems Division, and summarizes current and planned R&D on cooling towers being performed in the Heat, Waste, and Water Management Program.

For cooling systems that conserve water, the most serious concern is cost. Commercially available dry-cooling systems are about four times as expensive in total cost as corresponding conventional evaporative systems. Emphasis in EPRI research has been placed on achieving a substantial reduction in the cost of water-conserving cooling systems. Such systems will provide the industry with the most economical alternative to evaporative cooling where water scarcity rules out or severely constrains the consumptive use of water for power plant cooling.

The principal EPRI effort in this area is the demonstration of advanced wet-dry cooling technology based on an ammonia phase-change heat rejection system (RP422).

Construction of the 10-MW demonstration facility at Pacific Gas and Electric Co.'s Kern plant in Bakersfield, California, was completed in April 1981. A three-year operation and testing program, now in progress, is being conducted under the direction of Battelle, Pacific Northwest Laboratories, with Union Carbide Corp., Linde Division, serving as project adviser.

The overall test objectives are to demonstrate performance and operational feasibility; to demonstrate operability under "normal," steady-state, and transient conditions; and to demonstrate the ability to handle non-standard operation, such as recovery from an accident or power loss.

The results of the operational acceptance test in which the cooling tower was operated at 80% of full load showed that the major test components were operating properly, the cooling system reached steady state quickly, and the phase-change system operated in a stable manner.

A utility group has been formed to provide practical advice to aid in commercialization, as well as support for additional project tasks of specific interest to its members. The group currently consists of Pacific Gas and Electric Co., Southern California Edison Co., the Los Angeles Department of Water & Power, and the Canadian Electrical Association. EPRI is also cooperating closely with Electricité de France, which has built a 20-MW ammonia-based binary-cycle facility in France.

In a companion project, Chicago Bridge and Iron Co. has designed a capacitive cooling system for inclusion in the test facility (RP1260-23 and -27, RP422-12). The system, which features a water tank that functions as a thermal capacitor, eliminates water consumption for cooling and operates in a zero-discharge mode. It is economically comparable to the ammonia-based wet-dry cooling system when water is scarce for cooling. The system was constructed in 1982 and will be tested in 1983.

The economics of various water-conserving cooling systems have been compared by R. D. Mitchell, consulting engineer, in another companion project (R1260-21). This generic study covers the ammonia-based technology being developed under RP422, as well as both direct (steam condensation) and indirect (closed water loop) commercial cooling systems. Economic comparisons were made of optimized systems over a broad range of power plant sizes, fuel costs, water costs, and water consumption. It was found that the total cost of the direct system is less than that for the indirect system over the range of parameters considered.

In a related effort, EPRI has funded the

planning phase of a multiphase testing program to study the largest wet-dry cooling tower in the United States, located at the 500-MW San Juan-3 plant in Farmington, New Mexico. The Marley cooling tower is a cooperative effort of Public Service Co. of New Mexico and Tucson Electric Power Co. Under RP422-9 and -10, United Engineers & Constructors, Inc., and Environmental Systems Corp. developed a detailed management and test plan for evaluating the tower's performance with the goal of making data on such low-water-use systems available to other utilities. EPRI will retain an advisory role during the testing phase and will publish the results. The project offers an opportunity to obtain generic information on design, performance prediction, testing, and operation of a full-scale wet-dry cooling tower. The comprehensive study, under Public Service direction, will provide utilities with objective performance estimates of water consumption, economics, operations, maintenance, and system life. The test program is scheduled to begin in 1983.

In another related effort, Dynatech R/D Co. is evaluating the potential of nonmetallic heat exchangers for dry cooling (RP1260-29). It appears that cost reduction with nonmetallic heat exchangers should be achievable through new integrated heat exchanger concepts that include low-cost air and water conveyance systems and tower structure. In this study, Dynatech is reviewing potentially applicable nonmetallic materials, surveying the current use of nonmetallic materials in heat exchangers with emphasis on American and European applications, identifying and evaluating design concepts, and characterizing the development requirements of nonmetallic dry-cooling systems. Results will be published in an EPRI report in 1983.

In May 1982 an EPRI workshop on water-conserving cooling systems was held in Palo Alto to exchange information on recent developments in water-conservation technology for cooling power plants and to identify

future research needs. The primary focus of the meeting was on operating and testing such systems, but papers on economics, design, and so on, are included in the proceedings.

A closely related activity in the water quality subprogram is the control of the quality of closed-cycle cooling water. This work includes the use of municipal, industrial, and agricultural wastewater and brackish water, and it focuses on water treatment to control scaling, corrosion, and biofouling. A primary objective of this activity is the reduction in the importance of water as a major siting constraint by reducing makeup quantity needs and permitting the use of lower quality water.

These projects include the study of agricultural wastewater for power plant cooling, use of ozone to control biofouling, leaching of asbestos-cement fill into the cooling water, a binary cooling cycle to concentrate wastewater used for cooling, and chemical treatment of recirculated cooling water.

Performance

Work on the performance of conventional power plant cooling systems has emphasized the ability to specify, site, predict the performance of, and test cooling towers. The projects range from the development of computer programs for modeling interference and recirculation to the demonstration of field test procedures.

Projects are aimed at providing the utility industry with the experimental data and predictive capability required for the proper specification and evaluation of wet cooling towers. CHAM of North America, Inc., has developed a computer code incorporating a mathematical model capable of predicting the thermal performance of mechanical- and natural-draft cooling towers of both counter-flow and cross-flow design (RP1262). This code has been validated to the extent possible by comparing its predictions with available test data from existing cooling-tower installations.

A workshop was held in Chicago during October 1981 to present the complete computer code to the utility industry. The mathematical basis of the code was discussed and its input and output features detailed. Workshop participants had an opportunity to use the code to evaluate specific cooling-tower performance problems.

Another project involves the design, construction, and operation of a small-scale cooling-tower test facility (RP2113). Under a planning contract, Environmental Systems Corp. has identified key project elements, including potential utility cosponsors, utility

host sites, and facility instrumentation and structural requirements (RP1260-22). Battelle, Pacific Northwest Laboratories has developed a conceptual design of the facility, as well as a project management and test plan (RP2113). The test facility will provide an economical means of developing detailed performance data on existing and proposed cooling-tower fill configurations. To investigate performance under actual operating conditions, several fill configurations will also be tested in a dedicated cell of a cooling tower at the host utility (Houston Lighting & Power Co.) site. Testing of the facility, now being designed, is scheduled for 1983.

The CHAM predictive code will be validated further with test data obtained in the RP2113 project and will be used to design tests and extrapolate experimental results.

Plumes

The focus of the plume work to date has been the development of improved mathematical models for visible plumes and drift deposition from natural- and mechanical-draft cooling towers. The approach has been to use the most extensive data base available to ensure proper understanding and modeling of all major physical trends and to isolate specific elements of the models where improvements in the physics could substantially improve the overall predictions.

Mathematical models of plume dispersion from cooling towers, both natural draft and induced draft, are being improved for utility use in research at Argonne National Laboratory. Research to date is presented in a

comprehensive five-volume report, plus executive summary (CS-1683, Vols. 1-5; CS-1683-SY). A generalized model (with single-tower and clustered-tower submodels) has been developed to predict the seasonal and annual frequencies of visible plume impact, droplet drift, ground fogging, and icing of surrounding terrain. This work includes the development of methods to generate statistically reliable predictions of weather and tower operating conditions on the basis of data typically available to siting engineers. The overall objective is a flexible, reliable code for use in environmental impact and plant-siting studies. A workshop held in Chicago in September 1981 presented the current version of the code to the industry. Another workshop was held in October 1982, also in Chicago, to transmit the final code and documentation.

Some recent results in this project were obtained from a laboratory simulation of a cooling-tower plume produced in a wind tunnel at the University of Illinois (Figure 1). The plume resulted from discharging nitrogen gas at -190°C downward into a cross flow of air. Because of the low viscosity of the nitrogen at cryogenic temperatures, a fully turbulent discharge was achieved despite the reduced geometric scale of the simulation. The visibility of the plume stemmed from the humidity present in the ambient air. Plume trajectory and dilution are being determined by measuring plume temperature in a plane normal to the direction of the cross flow.

At present this laboratory simulation is

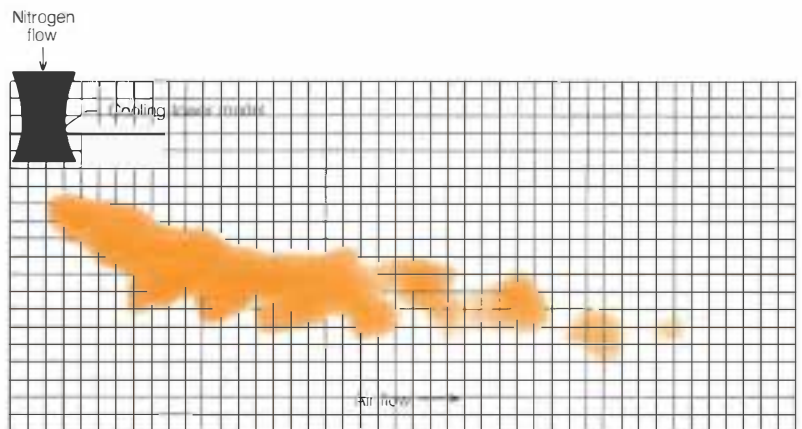


Figure 1 Laboratory simulation of a cooling-tower plume produced in a wind tunnel.

being tested against existing field and laboratory data on single-source plumes. Once it has been established that no scaling distortion is present, the facility will be used to study the merging of multiple-source plumes. Information gathered from this effort will be used to improve the multiple-source cooling-tower plume model.

Code development in the area of cooling-tower drift is being complemented by laboratory drift studies. A wind tunnel was constructed at MIT for evaluating various methods of plume droplet drift measurement against a calibrated reference method developed in this effort (RP1260-11). The system consists of a wind tunnel capable of producing drift conditions that would typically be encountered in utility cooling towers, a laser light source, an optical system that simultaneously senses the laser light scattered from the droplets, and electronic and automated data reduction systems.

Participants from the United States, the Federal Republic of Germany, and Belgium participated in measurements of a matrix of test environments in which droplet mass flux, droplet size distribution, and air speed were varied. The tests showed significant differences in results among the measurement methods. *Subprogram Manager: John A. Bartz*

AFBC PILOT PLANT

Atmospheric fluidized-bed combustion (AFBC) is being developed as a cost-effective alternative to conventional pulverized-coal combustion to generate steam for utility use. In AFBC, coal is burned in a bed of limestone that is fluidized by air distributed at the base of the bed. The highly turbulent, bubbling limestone bed rapidly absorbs the sulfur dioxide (SO₂) emitted from the coal during combustion, preventing the SO₂ from leaving the combustion zone—thus eliminating the need for costly postcombustion flue gas desulfurization systems. Another advantage of AFBC is its relatively low combustion temperature (1550°F [843°C] as compared with 2500–3000°F [1371–1649°C] in pulverized-coal systems), which is made possible by the boiler heat exchange surface that removes heat from the fluidized bed. The low combustion temperatures prevent the coal ash from being molten, eliminating the concern for problems associated with slagging and fouling of tube surfaces and making AFBC more flexible about fuel type than pulverized-coal systems. In addition, the low temperature limits the amount of nitrogen oxide (NO_x) formations to well below current federal standards.

Over the past few years, AFBC development has evolved to the point where industrial units ranging from approximately 20,000 to 200,000 lb of steam per hour are being built and sold in the United States and foreign countries. However, the utility industry's requirements for unit size, steam conditions, efficiency, availability, and load following indicate a need for additional development specifically to meet utility stipulations.

Since 1977 EPRI has conducted research on a 2-MW (e) AFBC process development facility at Babcock & Wilcox Co., Alliance Research Center (RP718). Design and process improvements made at this facility demonstrated the potential efficiency and cost-effectiveness of the process. Remaining technical uncertainties deal with process scalability and the operating and engineering aspects of the systems auxiliary to the process, particularly the cost, reliability, and performance of the coal-feeding system, the fly ash recycle system, and the control system. To adequately address these uncertainties, a scale-up unit of approximately 20 MW (e) was needed for the testing of commercial-size auxiliary systems similar to those that would be used in even the largest AFBC units purchased by electric utilities. In 1979 the Tennessee Valley Authority (TVA), in conjunction with EPRI, laid out the plans

for the design, construction, and testing of a 20-MW (e) AFBC pilot plant to be built by TVA at its Shawnee generating plant near Paducah, Kentucky. The plant is the intermediate developmental step between the 6 × 6 facility and a commercial-scale, 100–200-MW (e) demonstration plant, now in the early planning stages by EPRI. Based on the results of the 20-MW (e) pilot plant, the demonstration plant could be built and operating by 1990 at a host utility site.

Facility design, construction, and startup

Design specifications for the AFBC pilot plant were prepared by TVA and EPRI in the spring of 1979 and issued for competitive bidding in May. In September 1979 B&W was awarded a contract by TVA for the final engineering, fabrication, and erection of the pilot plant. Site preparation at TVA's Shawnee station began in the summer of 1980, with the foundation completed and structural steel erection commencing in August 1980. The boiler was erected during the summer of 1981 and underwent hydrostatic testing in November 1981 (Figure 2). The completion of the remaining major civil, electrical, and mechanical engineering features of the plant was on schedule by April of 1982, leaving only minor erection activities to be

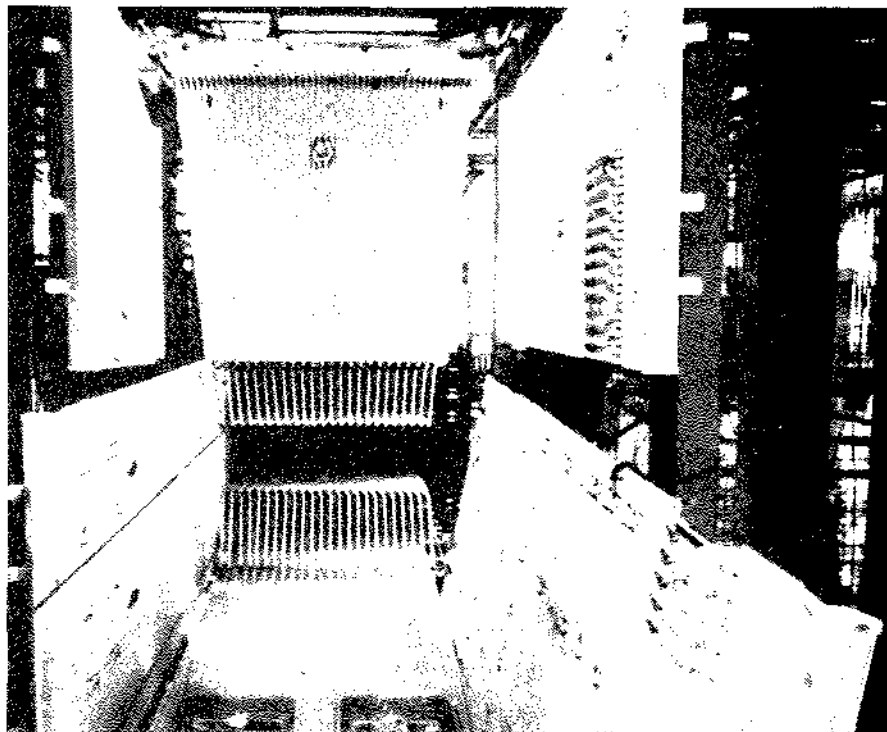


Figure 2 Waterwalls of 20-MW (e) boiler being set in place (view from bottom).

completed during the April–July 1982 time-frame. Parallel to the finishing stages of construction, plant shakedown and startup tests were performed as a basis for TVA acceptance of the various plant systems from B&W.

Critical to the timely startup of the plant was the shop fabrication, testing, delivery, and tie-in of the plant computer used for operational control and data acquisition. The computer underwent its factory acceptance test in November 1981 and was delivered to the site the following month. After successful integration of the computer as part of the plant's instrumentation and control system, all startup operations during the initial startup and shakedown phase were run and monitored safely from the central computer control panel.

Plant shakedown and preoperational tests culminated on May 2, 1982, with the firing of coal for the first time. After further debugging and test firing during May, the unit was operated at full load (steam conditions at 2400 psig [16.5 MPa] and 1000°F [538°C] superheat) for a 24-hour period on June 6 and 7. Late in June the fly ash recycle system, which is critical to efficient process performance, was placed into operation, signifying the completion of the facility construction and startup phase of the project and the onset of the TVA–EPRI operational test program. As of July 1, 1982, over 300 hours of operation had been logged on the pilot plant (Figure 3).

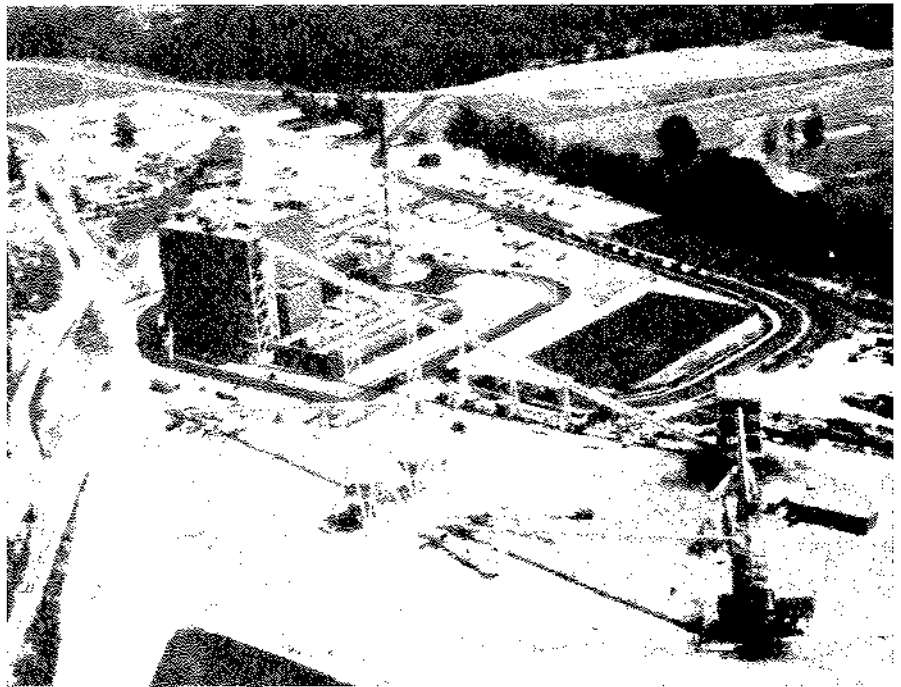
Test program

TVA and EPRI initiated a \$28.5 million test program in July 1980 (RP1860). The test program, scheduled to run through mid-1986, consists of two phases.

The first phase (completed on July 1, 1982) was the preparation phase. The objective of this phase was to prepare the resources necessary to use the 20-MW (e) pilot plant to readily accomplish the research objectives for which the plant was built. This phase consisted of operator and engineer training, development of test procedures, and development of the plant systems necessary for rapid data evaluation and analysis, including the computer, chemical laboratory, and the gas and solids sampling system.

Of prime importance during this phase was the development of a comprehensive test plan, which ties together AFBC development needs with the facility capabilities and formulates an R&D strategy framework on which the detailed test planning will occur. Developed jointly by EPRI and TVA, the test plan also establishes the project testing

Figure 3 AFBC pilot plant at TVA's Shawnee steam plant near Paducah, Kentucky.



schedules, priorities, and resource requirements.

The second phase of the test program, the implementation phase, is scheduled to run from July 1982 to July 1986. Its objective is to implement the plan through operational testing, data evaluation, and reporting. As defined in the test plan, the R&D strategy is to use the pilot plant to develop the design and operating bases necessary to allow evaluation of the trade-offs between capital costs, operating costs, availability, and control/cycling capability for the timely engineering of large-scale demonstration and commercial AFBC power plants. The testing of the project, therefore, will center on four major activities.

- Process hardware testing and evaluation
- Materials testing and evaluation
- Availability engineering
- Control system engineering

Process hardware testing and evaluation

The pilot plant can be used to compare and evaluate various auxiliary system design options for fuel feeding, fly ash recycle, and waste solids handling. The design and performance of these systems, peripheral but integrated to the AFBC process itself, could have a major impact on the cost and config-

uration of future demonstration and commercial plants. In late 1982 and early 1983, major emphasis in the testing will be on comparative evaluations of options for fly ash recycle and coal and limestone feeding. For the recycle system, the testing will characterize process performance over a wide range of fly ash flow rates and temperatures, as well as testing and evaluating the mechanical effects on components in the recycle loop. Future provisions concern recycling fly ash at even higher temperatures and at alternative locations in the combustor.

For coal and limestone feeding, two available methods of feeding the granular solid material into the fluidized will be compared and evaluated. The initial testing will be with pneumatic feeding of a coal and limestone mixture into the base of the bed. Later, this method will be compared with a method in which the coal and limestone are spread over the top of the fluidized bed (similar to the method employed in existing stoker-fired boilers).

The effects of these system design options on the configuration, capital cost, and operating cost of larger-scale systems are important in the decision-making process for the pilot plant. Bechtel Power Corp. is evaluating the impact of these system options on the cost of 200- and 500-MW (e) AFBC power plants (RP1860-3), receiving boiler design input from B&W (RP718-2). Trade-

offs in total plant capital cost, efficiency, auxiliary horsepower, and availability will be important factors in this evaluation.

Materials testing and evaluation

Although past research has indicated that high-temperature superheater materials, properly selected, can probably withstand the potentially corrosive and erosive environment of the fluidized bed (RP979), none of the tests has been carried out for a sufficient duration to enable confident extrapolation to the 30-year lifetime requirements of boiler materials. Nor have the units in which these materials tests were run been of sufficient size to warrant the use of commercial design and fabrication methods for the boiler materials and support members. The 20-MW (e) pilot plant offers an excellent opportunity to observe the long-term effects of the process on the integrity of boiler materials.

Pressure parts are being periodically monitored by nondestructive evaluation of tube metal thickness, primarily using ultrasonic thickness measurements and eddy-current examinations, as well as frequent visual inspections. Corrosion and erosion material specimen racks are being mounted in strategic locations in the bed and freeboard and will be removed for metallographic analysis after 5000–10,000 hours of operation. The corrosive environment in various points in the combustor will be monitored by extractive gas sampling and analysis and by an in situ oxygen probe to map the localized corrosive environment.

Availability engineering

Design specifications, equipment selections, and maintenance planning for future AFBC utility plants will greatly benefit from the data base of information on operating and maintenance histories and experiences with the equipment and system used at the 20-MW (e) plant. An extensive program for properly recording outages, failure-cause analyses, and maintenance has been enacted to systematically record this information.

In the area of preventive maintenance, nondestructive measurements on critical components are being used to diagnose and predict failures before they occur. This includes the use of material thickness measurements for solids-handling equipment (e.g., screw feeders, high-temperature knife gate valves, pneumatic transport piping elbows). Periodic monitoring of wear rates for component materials will allow early identification of probable causes and locations of component failure and provide a basis for

improvement in design and material selection for replacement parts and components.

Control system engineering

A major objective of the project is to enhance AFBC turndown and control capabilities so future units can be designed for cycling capacity. The integration of the combustion process to match turbine steam flow, pressure, and temperature needs will require proper design and allocation of the boiler heat transfer surface between the bed and convection pass, as well as proper integrated control of firing rate, recycle rate, and fluidized-bed depth. An advanced control system design approach has been adopted for the pilot plant project by use of a dynamic modeling and computer simulations developed by TVA. The effect of this design approach on standard boiler design practice is being evaluated by B&W (RP1860-4). The testing procedures to characterize the transient response characteristics of the pilot plant have been specified by Jaycor to validate the dynamic model (RP1179-10). Once validated, the model will be the basis for advanced multivariable control system design and evaluation. The pilot plant's direct digital control computer will allow simple modification and upgrade to the plant's control capabilities. *Project Managers: William Howe and Thomas Boyd*

SELECTIVE CATALYTIC REDUCTION

Federal and local regulatory agencies have proposed postcombustion control of nitrogen oxide (NO_x) emissions as a means of meeting emission standards significantly below those currently attainable through combustion control. This position is based on successful Japanese experience with one particular process, ammonia-based selective catalytic reduction (SCR). This experience, while extensive for fuels containing little or no sulfur and ash, is recent and limited with respect to coal-fired power plants at full scale. Although the experience has encouraged the view that SCR is a viable and commercially available NO_x control technique for the U.S. utility industry, major engineering and integration issues remain concerning full-scale, continuous-duty application—issues that could influence SCR feasibility and costs. EPRI is addressing these issues in work at its Emissions Control and Test Facility (Arapahoe) near Denver.

Engineering feasibility studies conducted by EPRI (RP783-2 and -3) have determined the levelized cost of SCR to be approximately 6–13 mills/kWh, with capital costs of \$52–

\$92/kW (1982 dollars). These costs are significantly greater than for combustion control (EPRI Journal, January/February 1982, pp. 18–25). Additional capital and operating costs for postcombustion control could arise, primarily from impacts of the SCR process's residual ammonia (NH₃) and by-product sulfur trioxide (SO₃) emissions on plant operation and maintenance. To identify the remaining integration issues so that the costs and operating requirements of SCR can be determined accurately, EPRI has sponsored pilot-scale tests of the process at the Arapahoe facility (RP1256-4).

Although the SCR assessment work included tests to confirm the NO_x removal performance and operating requirements predicted by the process developer and vendor, it focused on measuring the residual NH₃ and by-product SO₃ emissions and on assessing how these emissions could influence power plant operations. Of particular concern are the possible effects of the SCR process on the performance and reliability of downstream equipment—specifically, the air heater and the SO₂ and particulate control devices.

The project employed the integrated environmental control (IEC) pilot plant at the Arapahoe facility, which is capable of processing flue gas at a capacity equivalent to 2.5 MW (e). The plant configuration for this program featured an SCR reactor, an ammonia injection assembly, and process monitoring and control systems; a Ljungstrom regenerative air heater; and ancillary equipment for extracting flue gas and controlling the temperature and flow rate. The SCR reactor, the ammonia injection assembly, and the process control systems are not optimized for performance at pilot scale, but instead are representative of designs applicable to full-scale power plants. Thus the SCR reactor can be considered a slice from a full-scale unit that is capable of simulating catalyst geometry and mass transfer characteristics. The ammonia storage and control systems are scaled-down versions of designs appropriate for full-scale use. Similarly, the regenerative air heater is designed to simulate the thermal conditions (i.e., the temperature history of the heat exchange surface) and the air-to-gas leakage that are characteristic of full-scale units.

Test results

The test program has accumulated results from nine months of operation. Summarized here are the findings on NO_x reduction and NH₃ and SO₃ emissions; changes in flue gas NH₃ and SO₃ concentrations across the air heater; and air heater pressure drop.

Figure 4 presents typical performance data describing the influence of the NH_3/NO_x mole ratio on NO_x removal efficiency and residual NH_3 emissions. At the flue gas flow rate and temperature corresponding to full-load, steady-state conditions (5000 ft³/min, 680°F; 2.36 m³/s, 360°C), the number of moles of NO_x removed was approximately the same as the number of moles of NH_3 injected (Figure 4a). Under these conditions, the utilization of NH_3 decreased as the NH_3/NO_x ratio approached unity, as evidenced by the significant increase in NH_3 emissions (Figure 4b). Results from off-

design conditions not simulating full load indicated that NO_x removal efficiency did not significantly change (not shown), whereas NH_3 emissions could be significantly affected (Figure 4b). Lower flue gas temperatures tend to result in higher residual NH_3 emissions; lower temperatures in conjunction with lower flow rates (lower space velocities) have little net effect.

The oxidation of SO_2 to SO_3 by the SCR process catalyst was measured as a function of flue gas flow rate and temperature. Between 0.5 and 2.5% of the inlet SO_2 was oxidized to SO_3 . Lower flue gas tempera-

tures suppress the formation of SO_3 , whereas lower flow rates promote its formation.

The significance of the above results is that the NH_3 and SO_3 emissions produced at lower loads (off-design conditions) will be affected by both flue gas flow rate (space velocity) and temperature. Thus they will depend on catalyst geometry and the turndown characteristics of specific boilers.

Tests involving transient (non-steady-state) operating conditions were conducted to determine if excessive NH_3 emissions would result during load swings, either because of operation of the control and monitoring systems or because of delays in achieving thermal equilibrium between the catalyst and the flue gas as load and flue gas temperature increase. The results identified several weaknesses in control system operation. In one instance, for example, the control system and process monitors failed to maintain a 0.9 NH_3/NO_x ratio through a series of flow rate changes; ratios as high as 0.94 were reached, and the resulting NH_3 emissions were two to three times the steady-state values.

Figure 5 illustrates the change in NH_3 and SO_3 emissions across the air heater for two test cases—one using the test program's baseline coal, which produced a flue gas SO_2 concentration of 380 ppm at the SCR reactor inlet; and the other using an alternative coal that produced a similar SO_2 concentration but had a relatively alkaline ash. Both cases featured high NO_x removal (~90%). The figure presents concentrations at the air heater inlet and outlet for gas-phase NH_3 ; the total of gas-phase NH_3 and solid and liquid phases of ammonium compounds (NH_4^+); and gas-phase SO_3 . The ammonium compounds include ammonium sulfate and bisulfate (which are formed when NH_3 reacts with SO_3) as well as NH_3 absorbed or reacted on fly ash.

For the baseline coal, the residual ammonia at the air heater inlet existed predominantly as gas-phase NH_3 , with little NH_4^+ present. The gas-phase NH_3 decreased significantly across the air heater, while the total of NH_3 and NH_4^+ remained approximately the same, indicating the formation of ammonium compounds. Simultaneously, SO_3 was lowered across the air heater from 6 to less than 1 ppm.

Test results for the alternative coal did not follow the trends of the baseline coal; significant quantities of NH_4^+ were measured at the air heater inlet, and the gas-phase NH_3 concentration was virtually unchanged across the air heater. Gas-phase SO_3 decreased from 3 to 1 ppm. The alkaline ash of the alternative coal could be responsible for the reduced SO_3 concentration and thus

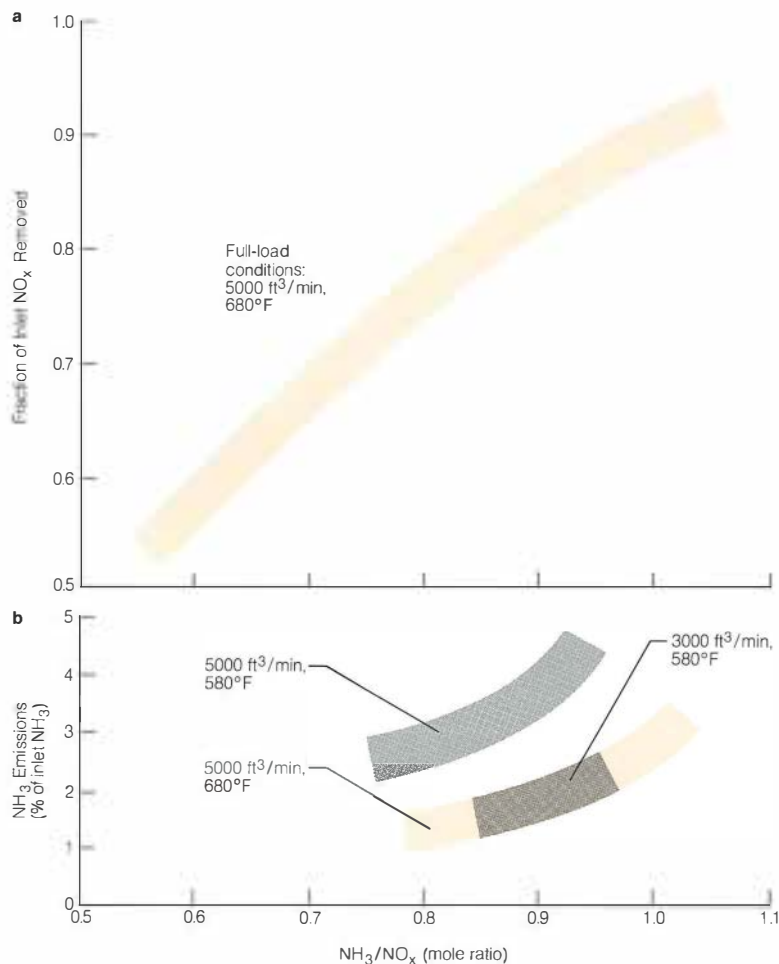
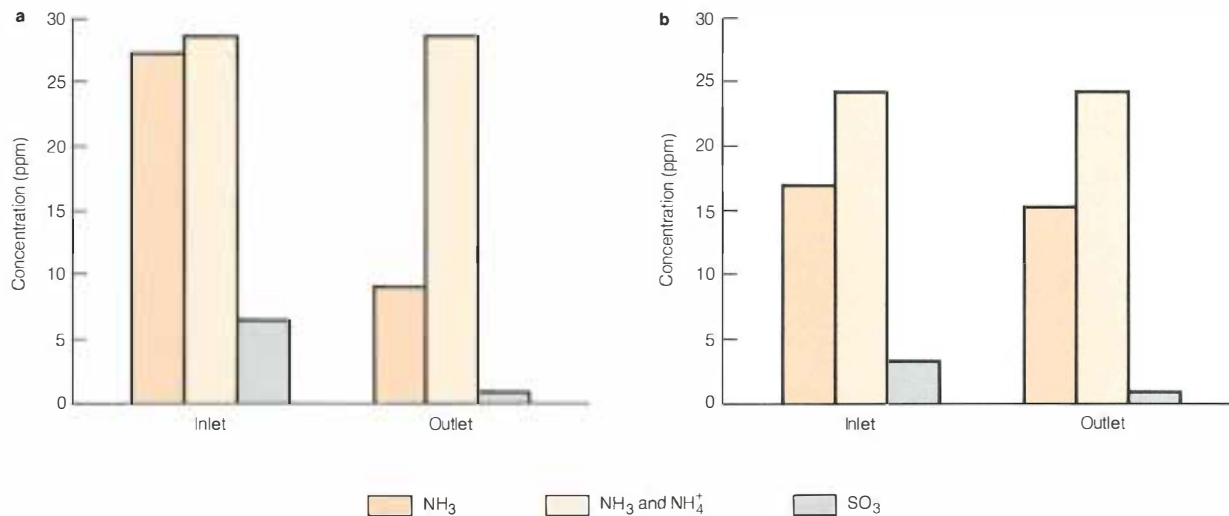


Figure 4 Influence of the NH_3/NO_x ratio on (a) NO_x removal and (b) NH_3 emissions. NO_x removal is shown for approximate full-load flue gas flow rate and temperature conditions. The number of moles of NO_x removed is approximately the same as the number of moles of NH_3 added. NH_3 emissions are shown for full-load and off design conditions. Under full-load conditions, the emissions increase significantly at an NH_3/NO_x ratio of about 0.9. Lower flue gas temperatures may increase NH_3 emissions, depending on the flue gas flow rate.

Figure 5 Flue gas concentrations of gas-phase NH₃, total gas-phase NH₃ and ammonium compounds (NH₄⁺), and SO₃ were measured at the air heater inlet and outlet in tests using (a) the baseline coal and (b) an alternative coal. The coals produce similar flue gas SO₂ concentrations (around 380 ppm at 3% O₂), but the alternative coal has a more alkaline ash; in both cases NO_x removal was ~90%. The concentrations of the compounds change as flue gas from the SCR reactor passes through the air heater and is cooled. Gas-phase NH₃ decreased significantly through the heater for the baseline coal but not for the alternative coal, whose more alkaline ash could have served as a sink for SO₃ and thus limited ammonium sulfate and bisulfate formation and NH₃ loss.



a reduced potential for formation of ammonium sulfate and bisulfate.

The loss of NH₃ and SO₃ across the air heater was accompanied by the formation of deposits on the heat exchange surfaces in a narrow region on both sides of the void between the intermediate and the cold-end baskets. These deposits could not be removed by normal soot-blowing with air, and they caused flue gas pressure drop to increase above levels experienced without SCR.

Figure 6 shows flue gas pressure drop across the air heater as a function of operating time for three test cases involving different NO_x removal levels and different SO₂ concentrations. (High-sulfur coals were simulated by injecting additional SO₂ into the baseline coal flue gas.) Pressure drop increased above non-SCR levels in all cases, with the increases being proportional to the SO₂ content of the flue gas and the degree of NO_x control desired. Deposits could be removed only by removing the air heater from service and washing it with water. An initial analysis of the deposits indicated the major constituents to be sulfates (60%), silica (as SiO₂, 18%), and aluminum and iron (each 8–10%).

Significance for SCR feasibility

NO_x removal performance and SCR operating requirements were consistent with the

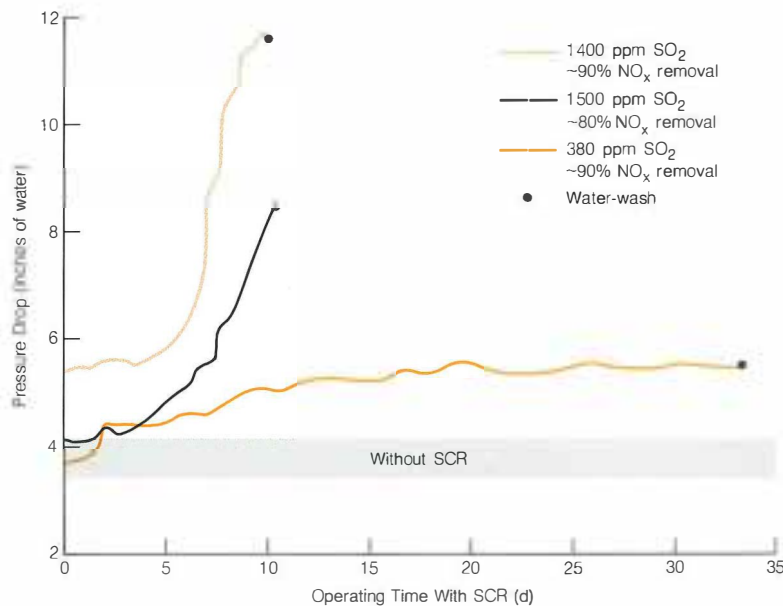


Figure 6 When SCR is applied to coal firing, flue gas pressure drop across a regenerative air heater increases significantly above levels without SCR because of the deposition of ammonium sulfate and bisulfate, which are process by-products. The amount of increase is dependent on operating time, the flue gas SO₂ concentration, and the level of NO_x control desired. As shown here (colored curves), at a fixed NO_x removal level, a rise in SO₂ concentration from 380 to 1400 ppm (at 3% O₂) causes pressure drop to rapidly increase. The increase is not as great if less NO_x removal is required (black curve). Only water-washing removes the deposits.

process vendor's predictions based on development work with non-U.S. coals.

A significant result is the one suggesting that the fate of residual NH_3 (i.e., whether it remains in the gas phase or forms ammonium compounds) depends on fuel type—more specifically, on the fuel's sulfur content and the alkalinity of its ash. These properties could determine the ratio of gas-phase NH_3 to SO_3 —the sulfur content by affecting the amount of SO_2 available for SO_3 generation, and the alkalinity of the ash by affecting the ash's ability to act as a sink for NH_3 or SO_3 .

If gas-phase NH_3 is reduced across the air heater and ammonium sulfate and/or bisulfate is formed, the resulting particulate compounds can be collected by the particulate control system, and penetration of NH_3 to the SO_2 control system is prevented or minimized. If ammonium sulfate and/or bisulfate is not formed across the air heater, NH_3 remains in the gas phase and can penetrate the particulate control system and reach the SO_2 control system. It is not yet known which situation is preferable.

The results on air heater flue gas pressure drop suggest greater heat rate penalties and operating and maintenance requirements in proportion to the level of NO_x reduction and the sulfur content of the coal. The concentration of deposits in the vicinity of the void between the intermediate and the cold-end baskets could be due not only to the location of ammonium sulfate and bisulfate condensation temperatures but also to the influence of the void on soot-blowing aerodynamics. The inability to prevent deposit accumulation under design soot-blowing conditions does not rule out success with higher air pressures or the use of steam; these modifications are not currently available at the IEC pilot plant.

If the presence of NH_3 and ammonium compounds in flue gas increases the cost of operating the power plant and/or other emissions control components, it will be necessary to select an NH_3/NO_x ratio not to maximize NO_x removal but to prevent excessive NH_3 emissions. Figure 4 suggests an NH_3/NO_x ratio of less than 0.9 if well-controlled, steady-state conditions can always be maintained. Because actual power plant operation will include transient conditions, however, the limitations of the process control system must be factored into the selection of an NH_3/NO_x ratio. If control system designs or the precision of the components cannot be improved, this factor alone may limit the NH_3/NO_x ratio to 0.8 and NO_x removal efficiencies to 75–80%.

Observations and future plans

On the basis of the test results and analysis, the following observations can be made about the feasibility of SCR and the impacts of the process on power plant operation.

- NO_x can be reduced to 10% of the SCR reactor inlet levels or less, but only under well-controlled, steady-state conditions and without regard for power plant or other environmental control equipment.

- The degree of NO_x control that can be practically attained will be limited by the loading of residual NH_3 and by-product SO_3 emissions in the flue gas and the impacts of these emissions on power plant and other environmental control equipment.

- NO_x control over continuous operating periods must be targeted at levels less than those attainable at steady-state conditions in order to minimize impacts on power plant and other environmental control equipment. On the basis of specific test conditions for the IEC pilot plant, reductions of at least 10

percentage points below the steady-state level will be required.

- Air heater pressure drop increases unacceptably with SCR application; the rate of increase is dependent on the SO_2 concentration and the degree of NO_x control desired. Off-line water-washing is required to remove deposits; conventional soot-blowing is inadequate. Although the deposits themselves may not accelerate corrosion, the removal and cleaning procedures may.

- The ultimate fate of residual NH_3 (i.e., collection in the particulate control system or in the SO_2 control system) could depend on the coal properties. Low-sulfur coal with alkaline ash could bias NH_3 to the scrubber, whereas a high sulfur content and acidic ash could favor collection as ammonium sulfate and bisulfate particles.

- SO_3 concentrations can be reduced across the air heater to less than 1 ppm from initial levels as high as 15 ppm (at 3% O_2). This may permit lower flue gas rejection temperatures and thus have a favorable effect on heat rate, depending on the form of NH_3 at lower temperatures.

Tests are currently being conducted to establish the impact of SCR on fabric filter performance, characterize hopper ash to identify disposal requirements, and evaluate the performance of a special-purpose catalyst with reduced SO_2 -to- SO_3 oxidation characteristics. These results will be available this fall.

Further tests will be conducted under the IEC subprogram (RP1646) to examine the performance and costs of IEC systems consisting of an SCR reactor, a wet SO_2 scrubber or a spray dryer, and an electrostatic precipitator or a fabric filter. The first interim report is scheduled for fall 1983.
Project Manager: J. Edward Cichanowicz

R&D Status Report

ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

UNDERGROUND TRANSMISSION

Water-jet concrete cutter

Discovery of innovative techniques to reduce installation costs of underground cable is one of the major objectives in the Underground Transmission Program. One such novel idea is using pressurized water to cut asphalt/concrete roadways prior to trenching operations. Historically, cutting with high-pressure water used no additives or abrasives and operated at 56 ksi (382 MPa). This required expensive equipment because components capable of operating at extremely high pressure are specially built. Under a current research effort, abrasive/water mixtures have been evaluated by Flow Industries, Inc. (RP7860-1), culminating in simplified equipment and nozzles that have been incorporated with a previously developed EPRI concrete-cutting vehicle (Figure 1).

By using such abrasive additives as silica garnet, Flow Industries has demonstrated that concrete/aggregate and composite reinforcing rod substrates can be cut at 30 ksi (205 MPa), using reduced horsepower. This means that most equipment is off the shelf and smaller in design.

The advance rate for producing two simultaneous cuts is now anticipated to be 12 in/min for 8-in-thick concrete; 4-in asphalt with aggregate can be cut at a rate of 3–5 ft/min on both sides of a trench.

Cutting efficiency depends on many operating variables. The size of the abrasive particles seems to have a significant effect on efficiency. Large granules, approximately 0.5 mm diam, are used for road work. Fine powders are used for materials like stainless steel or metals.

Preliminary field demonstrations in the Seattle area cut straight edges as deep as 10 in. The roadway was made of an extremely

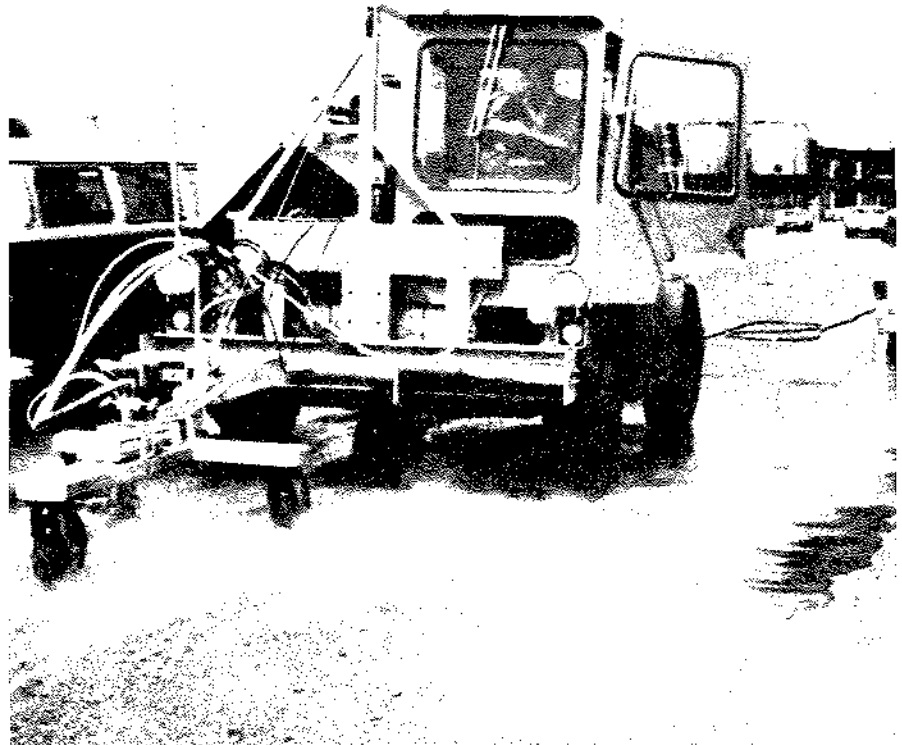


Figure 1 Water jet concrete-cutting vehicle, fitted with its new front-end assembly and abrasive/water nozzle, undergoing field demonstration in Seattle. Note the steam rising as a result of the friction heat produced by high-velocity water and particles impinging on the substrate.

difficult composite: 4 in of asphalt/aggregate over two crossed layers of red brick and approximately 6 in of concrete/aggregate. Although unable to cut totally through the 15–18 in, good, clean cuts were made in an actual cable installation operation. Utilities interested in using this technology should contact Flow Industries. *Project Manager: Thomas Rodenbaugh*

TRANSMISSION SUBSTATIONS

Carrier frequency noise from HVDC converters

The goal of this project was to develop a procedure for calculating the electrical noise produced by an HVDC converter station (RP1427). Primary emphasis was placed on the 10–300-kHz band of frequencies, which

is used for carrier communications. Implicit in this goal was a demonstration of the degree to which calculated noise levels agree with measured noise levels.

In large measure, the goal was reached, even though budgetary considerations precluded carrying some of the work as far as desired. Some areas that were investigated suggested research that should be pursued in the future. Areas of investigation that were carried to a satisfactory conclusion included measurement of the noise levels actually produced by a dc converter, development of equivalent circuits of the major elements affecting the noise, and development of a method of simulating a dc converter with the aid of the electromagnetic transients program (EMTP).

Results indicated that the noise levels obtained by calculation were higher than measured levels. The levels are in reasonable agreement at low frequencies but diverge at higher frequencies. This suggests that there is more attenuation in the actual converter than was accounted for in the equivalent circuits.

The only losses included for the purpose of calculation were those in the smoothing reactor, and these losses were represented in only the simplest way. No losses were included in the transformers. Detailed equivalent circuits were developed for the converter transformers and the smoothing reactor, but at present there is no rigorously developed methodology for incorporation of losses into those models. A method was developed for representing losses in the smoothing reactor, but this was a trial-and-error method that compared measured impedances with calculated impedances. By arbitrarily placing resistors in the model, it was possible to get reasonably good agreement between measured and calculated response. No attempt was made to do the same on the converter transformers.

One area of research that should be pursued in the future is the incorporation of losses into the converter transformer model, as was accomplished for the smoothing reactors. Another would be to incorporate those detailed models into the complete model of the converter. Although this would increase the complexity of the model, it is within the dimensional capability of the EMTP. If incorporating the losses results in the calculated noise values being closer to the measured values, it will be possible to see if simpler models, also with losses, will be sufficient. It might be necessary to have several different representations of the losses, each fine-tuned to give best results

over a particular band of frequencies. Another activity that should be considered is the effect of unbalanced impedances in the converter transformers, specifically the effect of noise generation. The few measurements that were made of waveshape on the converters indicated that the ripple voltage was not the pure, 12-pulse ripple predicted by theory.

Several other items might be pursued in a future set of field measurements. First, more detailed measurements could be made of actual waveshapes produced by an operating converter. The bushing capacitance tap voltage dividers used in the second series of measurements would permit measurements to be made on both the line and valve sides of transformers and smoothing reactors. By comparing calculated and measured waveshapes, it might be possible to determine which elements of the circuit were the most important contributors to the noise.

Second, voltage and current into and out of transformers and smoothing reactors could be measured for better prediction of the impedances as functions of time or frequency.

Third, the question of the effect of noise produced by converters on the performance of carrier systems was not conclusively investigated. Allowable signal-to-noise levels for carrier systems have been established, mostly by investigating how white noise affects the intelligibility or usability of carrier signals. The noise produced by a converter, however, is not a white noise. At any one frequency the instantaneous noise amplitude is not constant but is a probabilistic function, sometimes high and sometimes low. The measurements gave a good picture of how the levels, average and quasi-peak, varied with frequency but did not adequately expose the entire probabilistic, time-varying nature of the noise. Determining the usability of such measurements and perfecting the measuring techniques could form the basis of a future project.

Finally, the converter probably excited all the various modes of propagation on a transmission line, both high loss and low loss. Determining how the converter noise propagates along a transmission line might also form the basis of a future program, either theoretical or experimental. *Project Manager: Gilbert Addis*

Substation grounding

With the emergence of sophisticated computer models that analyze the performance of substation grounding grids, engineers ask how accurate these new computer models

are and if substation grounding grid design can be fine-tuned by relying on the accuracy of these new techniques.

To provide answers to these questions, a project has recently been completed at Ohio State University; its objective was to determine the performance of various substation grids in a variety of soil conditions by using reduced-scale models (RP1494-3).

Models have long been recognized as a low-cost, quick method to simulate real-world conditions and observe the performance of substation grounds. Pioneers in the development of designs for substation grounding recognized the value of scale models, and some early work with models, although crude by today's standards, gave answers sufficiently accurate for early design methods.

In this project, great care was exercised in the modeling and data acquisition, and the effects of the variation of parameters were recorded. For example, a grid model was built with ground rods extending deep into the earth. By clipping off the rods in successive steps, the effects of using shorter and shorter rods could easily be observed.

The results of the scale-model tests were compared with the output of a computer model developed by the Georgia Institute of Technology (RP1494-2). Good agreement was observed. Comparisons were also made with various grounding analysis methods in popular use today, including IEEE Standard 80. Since these are approximate methods, agreement was not as close as it was with the computer model.

This project's results are important if confidence can be gained in the use of the new computer models. By taking advantage of the ability of the model to precisely analyze each area of the grounding grid, substantial cost saving may be achieved by reducing the length of copper grid conductor required.

Project Manager: John Dunlap

HVDC-AC harmonic interaction

Present ac filter designs for HVDC systems incorporate conservative assumptions of system characteristics, leading to either overdesign or, at best, varying margins of voltage and current stress on equipment. Improved methods are needed to characterize the ac system harmonic behavior if the filter design and performance assessment process is to be improved.

General Electric Co. has evaluated past design practices and investigated methods for calculating system harmonic impedances (RP1138). A set of references related to filter design has been assembled and a computer

program prepared for two methods of calculating harmonic impedances.

In the measurement method, an instrumentation system for measuring system voltage and current has been assembled and shown to have the required accuracy. Different schemes for using the voltage and current measurements in impedance calculations have been studied. In the analytic method, a procedure to include various operating conditions has been proposed.

The results of the measurement and analytic methods have been compared, and both provide reasonable results with substantial agreement for most harmonics. The precision can be improved by performing a sensitivity analysis with respect to frequency. The computer program provided for this analysis is capable of handling 400 buses, 600 lines, and can be easily expanded. New models can also be added easily, if needed.

The final report to be issued this fall can be used in several ways. For power engineers interested in ac filter design, Section 2 serves as an introduction; it explains how to combine one's knowledge of system harmonics generation and harmonic impedances so that filters can be designed to meet certain performance and reactive power needs. For those who want to pursue the subject further, an extensive, annotated bibliography on harmonic generation and filter design is in the appendix. *Project Manager: Gilbert Addis*

HVDC electronic current transducer

A digital electronic current transducer (ECT) for HVDC applications has been built and installed for trial operation at the Sylmar Converter Station by the Los Angeles Department of Water & Power (RP668-2). The

ECT, which meets the known accuracy requirements for dc metering purposes, was developed by General Electric Co. (EL-1343).

The ECT is rated 400 kV and 2000 A, with a 4000-A continuous overload rating. The top of the unit contains a current shunt and electronic equipment for conversion of the current to an optical signal. This signal is transmitted by hair-thin, optical waveguides brought from the top of the unit, through a porcelain column, to the control room of the terminal. The porcelain column houses a 30-kHz, 10-stage cascade transformer that feeds power to the electronic equipment in the energized head of the unit. The optical signal is reconverted to an electrical signal in the control room, which can be up to 300 m away from the ECT (Figure 2).

The ECT has been in operation at Sylmar since December 1978; its early operating history was described in the December 1980 *EPRI Journal*. After improvements of the signal power levels in the fiber-optic link, the system has been performing well. Only one component failure in the encoder unit has occurred during the 3.5-year operation of a fully redundant measuring system, which is equivalent to seven unit-operating years (well within its expected reliability). No explanation for the component failure was found.

One of the main objectives of the trial operation was to determine if the design was stable and rugged enough for the utilities. Of particular interest was the long-term stability of the analog/digital units. These were monitored by tracking the performance of the ECT's response to zero current inputs. So far, no significant long-term drift has been noticed. The ECT was interfaced with a digital dc revenue meter in

September 1981 (RP1510). Some grounding problems were found and corrected in conjunction with the installation tests of the digital revenue meter. The evaluation is now continuing with emphasis on the use of the digital data.

The indoor installation exposes the ECT to higher-than-normal average temperatures, but because it does not represent the extreme temperatures and temperature variations found in outdoor locations, outdoor testing may also be conducted. *Project Manager: Stig Nilsson*

Cesium vapor lamp system for triggering photthyristors

The electric utility industry is finding increased applications for solid-state switching systems used in phase control and high-voltage dc converters. These systems are composed of a multitude of thyristor (silicon-controlled rectifier) switches connected in series/parallel configurations to provide high-voltage-high-current capability.

Recently, it has become feasible to trigger high-power thyristor switches by the direct action of infrared light on a photthyristor. Systems employing such thyristors have the advantage that the triggering light signal is carried by electrically insulated fiber optics, and special insulation is not required for the gate circuit. An additional advantage is that the fiber-optic cable is immune to electrical noise pickup and the attendant possibility of destructive accidental triggering.

Laser diodes have been the prime candidate for the intense pulses of light required to trigger the photthyristors. However, each laser diode can only trigger a few photthyristors, so hundreds of laser diodes and their power supplies are required in an HVDC station. The potential cost and complexity of such a system provided the incentive to develop the pulsed cesium light source, where a single lamp can turn on hundreds of thyristors simultaneously.

Previous work on pulsed cesium lamps yielded promising lamp life and total light output (i.e., one lamp could trigger several hundred thyristors). However, the light intensity that could be delivered to the thyristor gates at the end of 18-m-long fiber-optic cables was marginal. Rather high pulse currents (2000 A) appeared necessary to reach the goal of ten times the thyristor threshold intensity.

In this project, large increases in effective light output intensity were obtained by advances in the lamp design and by using more efficient fiber-optic cables. The new cesium amalgam lamps contain mercury in addition

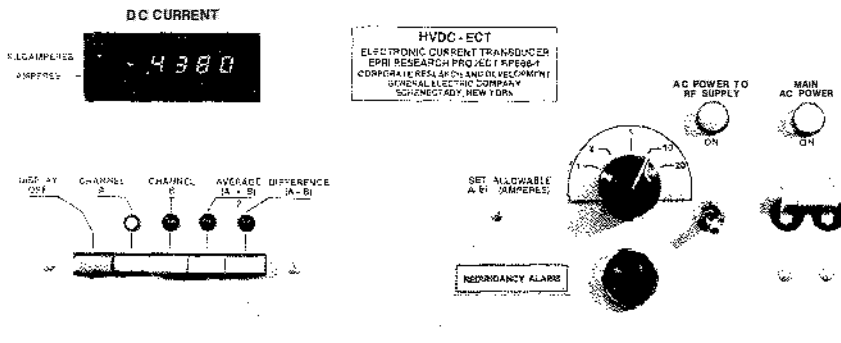


Figure 2 Receiver unit for the HVDC electronic current transducer (ECT) mounted in Los Angeles Department of Water & Power's Sylmar Converter Station for field testing. The receiver is tied to the ECT by a 300-m-long, low-loss, optical waveguide.

to cesium and have a reduced bore to increase the arc intensity. Single-fiber, fused silica cables of remarkable efficiency were tested.

The circuit that supplies electric power to the lamp consists of a pulsing circuit that provides the short high-current pulses and a keep-alive circuit that maintains a steady current through the lamp to keep it hot and conducting.

The pulsing circuit charges a pulse capacitor to a high voltage (1000–3000 V) and discharges it through the lamp by fast thyristors. Rapid recharge of the pulse capacitor is obtained by an inductive voltage-doubling circuit, while a separate HV trickle charger keeps the capacitor fully charged during prolonged periods without pulsing, so that the first current pulse is of full intensity.

The keep-alive circuit provides a current of 0.4–1.5 A to the lamp at 20 kHz. A dc keep-alive current is not suitable for cesium amalgam lamps because it causes segregation of cesium and mercury along the arc axis (cataphoresis).

In operation, the lamp temperature and pressure are controlled at the desired levels by using a variable series inductor to adjust the keep-alive current. This maintains lamp stability for experimental test runs. However, for a commercial installation with varying and arbitrary pulsing schedules, it appears necessary to provide electronic or computer feedback control.

Fiber-optic cables are used to guide light pulses from the cesium lamps to the individual photothyristors. The input end of the cable is aimed at the arc center from as close as possible, while the output end is aimed at the gate area of the photothyristor. The cable may have splices and disconnects as needed to provide redundancy and flexibility. Initially, multifiber cables were tested. Subsequently, single-fiber cables of 400–600 μm diam were found to have a gain of 2.5 compared with the best multifiber cable. Low connector losses (1–1.5 dB) were measured routinely.

As a result of these improvements in the lamp and in the fiber-optic cables, ample light intensity has been obtained at the thyristor gate over an optical path of 18 m at moderate pulsing currents. For instance, 33 times the threshold light intensity has been delivered to an experimental photothyristor by using pulse currents of only 300 A.

The conclusion is that a cesium amalgam lamp with 300-A pulses will have sufficient output intensity for triggering photothyristors in electric utility applications. At such moderate current levels there has been no

fundamental limitation to lamp life observed during tests that have reached 40,000 hours (8.5×10^9 pulses) for two cesium lamps and 6000 hours (1.3×10^9 pulses) for a cesium amalgam lamp. At a 300-A pulse current, the stresses on the lamp and on the power supply are moderate, and a triggering system that is reliable and moderately priced appears feasible. *Project Manager: Gilbert Addis*

Forced vaporization cooling of HVDC thyristor valves

Traditional cooling of large HVDC power conversion equipment has been achieved by forced-air cooling. The limitations of conventional air-cooled systems have brought into consideration convective cooling by liquid or forced evaporative cooling, in which liquid boils in a heat sink adjacent to the power-dissipating element. Forced evaporative cooling is the more efficient method when considering the size of the electrical components, the high power densities that can be accommodated, and the compactness of the system involved.

A simple forced vaporization cooling system will include a pump to circulate the liquid through the heat sink passages, where the coolant boils and cools the heat-generating elements, and a cooler or condenser, in which the vapor-liquid, two-phase coolant can be condensed into a single-phase liquid before returning to the pump. Design considerations of such a system and its operational limits benefit from the large body of two-phase flow and heat transfer information that has been generated recently in the nuclear and chemical industries. The data and design correlations developed in these industries, however, are applicable only within their respective ranges of operation and do not involve operation under high electric potentials. Further, because of size restrictions, HVDC power conversion equipment necessitates small, short, interconnected passages, a situation quite different from requirements of the nuclear and chemical industries. Thus, analytic models had to be developed and systematic experiments performed in order to develop the necessary understanding and design correlations for the forced vaporization cooling equipment. For the power conversion equipment, a refrigerant (Freon R-113) was chosen as the preferred coolant because it possesses high dielectric strength, boils at moderate pressures (i.e., below the 2.07×10^5 N/m² pressure limit, above which the ASME boiler code needs to be followed), has low saturation temperatures, and is compatible

with materials commonly used in electrical equipment.

The following technical barriers had to be overcome before any heat sink design considerations could be undertaken.

- The onset of nucleate boiling in small coolant passages had to be determined.
- The boiling heat transfer coefficient between the heat sink wall and the coolant in small passages had to be correlated with the important parameters to characterize the cooling efficiency of the system.
- The critical heat flux limit or maximum vapor content limits, which set the operational limit for the heat sink before dryout and burnout occur, had to be investigated.
- The pressure drop caused by friction, acceleration, and 180° bends had to be correlated for evaporating coolant flow in small passages.
- The thermohydraulic stability of the individual heat sinks and the loop that circulates the coolant had to be determined.
- The voltage levels that can be permitted in the coolant passages had to be fixed because the two-phase transfer lines connect electrically live, heat-generating components to the rest of the system.

Although it was realized that the single-cycle surge transients would only involve the device packages themselves, sufficient thermal margin had to be provided to hold the thyristor silicon temperatures below specified limits.

General Electric developed the necessary analytic tools and the experimental data necessary for the thermohydraulic design of a two-phase Freon-cooled thyristor panel (RP1207). Computer models were developed to permit extrapolation of experimental data for design use. A thermohydraulic demonstration model was built and tested with satisfactory results. Ultimate use of the data acquired will consist of the design and construction of a two-phase, Freon-cooled thyristor valve for installation and test at a host utility (RP1291-3, -4, -5). *Project Manager: Gilbert Addis*

ROTATING ELECTRICAL MACHINERY

Fiber-composite retaining rings

The purpose of a recently completed project was to develop a fiber-composite retaining ring for turbine generators (RP1474). The impetus for the project was that existing alloys

are yield-strength-limited to a 43-in diameter and subject to stress corrosion cracking as well. In addition, utilities must rely on off-shore suppliers for all large retaining rings.

During this project, two $\frac{2}{3}$ -scale graphite fiber-epoxy retaining rings were designed and fabricated by a bias-ply winding process. The rings were subjected to rigorous testing, including subjecting one ring to 2.8 times the normal operating stress. The rings showed no significant damage during these tests. However, two major technical problems must be resolved before the rings can be installed on turbine generators: ring attachment and circulating currents. Although this project provides conceptual designs to solve these two problems, detailed design, fabrication, and testing will be needed to prove the concepts. This will require a separate research effort. *Project Manager: D. K. Sharma*

Transformer oil pumps

The oil pumps currently used in transformers can have failure modes (such as bearing failure and impeller breakage) that can produce metallic debris. This debris is swept into the transformer by the oil discharged from the pump and may settle on the insulation structures of the transformer. A significant number of pumps have failed in recent years, principally because of the failure of bearings or impellers. Should this result in failure of a large power transformer, it could be very costly, in terms of both its repair and (in some instances) the cost of replacement power.

The objective of a recently completed project was to design, build, and test an improved transformer oil circulating pump (RP1797). Such a pump must be able to perform its required functions satisfactorily without the risk of contaminating the transformer in the event of a pump or pump-drive failure. A further requirement of the project was that the concept to be developed must be suitable for application to transformers of any manufacture. Retrofit capability was an additional project objective.

A detailed prototype design of the pump, based on a rotating casing pump concept, has been completed, including preparation of detailed layout drawings. It has been decided to terminate the project at the design completion stage and not proceed with the prototype manufacture and test phases because a major manufacturer has independently developed a transformer oil pump with the same objectives. This pump is currently being tested at utility sites.

It is the intent of the manufacturer to make

the pump available to all original equipment manufacturers and to all utilities for retrofit. In view of this development, EPRI will publish a detailed report on only the design aspects of the rotating casing pump. *Project Manager: D. K. Sharma*

OVERHEAD TRANSMISSION

Mitigation of geomagnetic-induced and stray dc currents

Geomagnetic storms triggered by solar activities induce voltage gradients between different points of the earth's surface. This can cause quasi-dc currents to flow through system grounding points that are remote from one another. Power systems in northern latitudes are most susceptible to these geomagnetic storms. The interconnected systems of three utilities—Manitoba Hydro-Electric Board, Minnesota Power & Light Co., and Northern States Power Co.—are one such example.

Geomagnetic-induced voltage gradients of 6 V/km and higher have been observed after severe magnetic storms. Currents on the order of 50–100 A have been observed in grounded neutral points that are separated by several hundred kilometers. This quasi-dc geomagnetic-induced current (GIC) flows into the neutral point and into each phase of the transformer. It then flows along the transmission line to exit in the same manner at the remote grounded neutral point. A previous research project (RP1205-1) investigated the effect of GIC on the Winnipeg–Duluth–Twin Cities 500-kV transmission line. This research project showed that GIC can cause half-cycle saturation in power, current, and potential transformers. This, in turn, can cause unusual real and reactive power flow, undesirable harmonics, and misoperation of protective relays. The results of this work have been published (EL-1949).

As a result of the earlier work, the current research project (RP1770) was initiated with Minnesota Power & Light, the University of Minnesota, Commonwealth Associates, Inc., and Phoenix Electric Corp. to accomplish the following.

- Determine the impact of GIC on ac power system operations and establish guidelines for system operators
- Develop guidelines for selecting the equipment to be applied on ac systems where GIC is expected (including transformers and reactors, circuit breakers, and relay and protective systems)

- Determine the effect of GIC and stray dc currents on HVDC system operations

- Conduct a technical and economic evaluation of special devices to block or mitigate GIC

Work in these areas is progressing well. It is expected that a final report will be issued early in 1983. Also, a workshop on this subject is currently in the planning stages and is expected to be held at the University of Minnesota in mid-1983. *Project Manager: Joseph W. Porter*

POWER SYSTEM PLANNING AND OPERATIONS

Array processor power flow

Many static and dynamic power system computations are based on power flow calculations. In recent years utility engineers have experienced increased difficulty in acquiring the number of power system simulations needed to solve today's complex problems. The difficulty arises from the large amount of computer time required for such a great number of simulations, the shortage of computer storage, and cost limitations. Further, if a utility's corporate computer is also used for engineering planning studies, financial and other nonengineering tasks often take priority over engineering computations. Thus, engineers need access to other, improved computation facilities if they are to obtain solutions in a timely and cost-effective manner. Similar problems exist in real-time applications because many energy control center computers are fully utilized.

Fortunately, computer hardware has undergone many changes in the last several years, including new architecture, improved computation speeds, and reduced equipment costs. The array processor is a good example—it is low in cost and it is a peripheral device that can be attached to a general-purpose (host) computer.

The main objective of RP1710 with Boeing Computer Services, Inc., is to determine the applicability of array processors to power flow computations. Boeing is restructuring the Bonneville Power Administration (BPA) power flow program to execute efficiently on an array processor. This restructuring has also been found to improve the execution efficiency on sequential computers. When the project has been completed, Boeing will deliver to EPRI the original BPA program, the restructured host-only program, and the host-array processor program. The modified, host-array processor algorithm is being in-

investigated for use in such applications as optimal power flow, transient stability, contingency evaluation, real-time applications, and operations control.

The second objective of the project is to determine the desirable hardware and software features for a host computer—array processor combination without regard to present market availability. The third objective is to assess the effect of an array processor with power flow software on optimal power computations, both now and in the future. *Project Manager: John Lamont*

Advanced concepts application

Advanced computer concepts were recently applied during research designed to arrive at new modeling, computing, and analysis techniques to solve power system planning and operations problems (RP1355). The topics of research were chosen from those offered during an open solicitation to universities. Four separate contracts were let, and all were completed in 1981.

At Northwestern University, researchers ascertained how well small, inexpensive microprocessors working in parallel could do the work of one large, expensive computer in performing system simulations. This was to help power system planners and operators, who need fast and inexpensive ways of doing simulations, to understand the many ways that a power system can fail. As a test of this concept, a 1200-bus transient stability simulation was performed with 50 micro-

processors in parallel. A 20-fold speed-up in solution time was realized in this test. Researchers showed that the ideal of a 50-fold speed-up, using 50 processors, cannot be achieved because of the need to schedule parallel tasks and communicate between microprocessors. The published results of this project (EL-1756) show that simulations can be performed faster and less expensively by using distributed rather than central computer processing, and they provide a foundation for hardware demonstration of this technique.

In another contract, Cornell University researchers evaluated the computation advantages of performing a load flow with an array processor computer. They found that an array processor can solve a simple 118-bus load flow five times faster than a large computer alone. From this research, it can be projected that a 1000-bus load flow can be solved in one-half second with an array processor. On-line control centers need computation speeds on this order to assess the effects sudden outages will have on system performance. However, difficult programming problems need to be overcome before this level of performance can be achieved with array processors. The results of this project were nevertheless transferred for use in RP1710 (power flow calculations using array processors). The final report (EL-2363) was published in April 1982.

The purpose of a third contract, with Iowa State University, was to develop an advanced

method of quickly, accurately, and inexpensively ascertaining when a power system is in danger of becoming unstable. A technique for directly calculating first-swing stability of large power systems without a step-by-step time solution was developed and tested on a moderate-size example system. The high speed and low cost of this technique permit the study of a large number of situations quickly and inexpensively. Further, the technique computes how close to instability the system is for a given situation. Thus, an indication of the margin of safety (or insecurity) is provided, and the system planner or operator can be alerted if potentially unstable conditions exist. Further development and testing of these results will be the subject of a future EPRI report. The final report of the initial research has been published (EL-1757).

Researchers at the University of Nebraska studied a new method to automatically forecast hourly load levels by using a model based on historical data and weather information. The statistical technique adapted for this research required a minimal amount of user judgment and intervention. For this reason the method developed has some advantages over the commonly used Box-Jenkins method. However, further research is needed to extend, improve, and test this method before it can be considered an alternative to the Box-Jenkins method. The final report has been published (EL-1758). *Project Manager: James Mitsche*

R&D Status Report

ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

PLANT CONSTRUCTION LEAD TIME UNCERTAINTIES

Increases in power plant lead times result from delays. Although coal-fired plant construction lead times have become slightly longer over the last decade—from an average of 56 months for a plant started in 1968 to 68 months for a plant started in 1976—they have not increased as much as those for nuclear plants, which have risen from 68 months to about 105 months in the same period. These long and increasingly uncertain lead times have created problems for utilities, particularly by raising capital costs and making planning for future load growth more difficult. EPRI has undertaken a two-year research project to develop lead time estimating models for nuclear and large coal-fired projects (RP1785). Although the main focus of the research has been on developing improved methods for estimating lead times, the project has two other objectives: to identify, to the extent possible, the specific ways of reducing and controlling construction schedules; and to identify areas in which further research is needed.

Several phases of the project have been completed. Following the development of an analytic plan and a strategy for gathering data, EPRI worked closely with a number of utilities to develop and analyze detailed case studies of construction histories for large coal-fired and nuclear units. Publicly available data were then used to replicate the analysis and test what was learned from the case studies. A number of utilities have participated in the study. Twenty-two companies reviewed the analysis and provided some lead time information. Fifteen of the companies helped assemble the detailed case histories for 30 coal-fired units and 27 nuclear-powered units.

The EPRI study reaches quite different conclusions than most lead time research for several reasons. The case history data separated the transitory causes of schedule

delays from more permanent ones. The research focused on the construction period and not on licensing or total lead time. The analysis separated plants by year of construction start so that plants of different vintage were not combined.

Key elements in lead times estimates

A lead time estimate must take into account three important factors: lead times for average plants over time, whether recent industrywide problems are permanent or transitory, and whether the lead time for a specific plant is likely to be long or short. It is therefore necessary to understand types of delays and the reasons they occur.

The research defined construction lead time as the sum of the initial estimate made at the start of construction plus delays. Delays can be divided into two categories—out-of-scope delays and construction slowdowns. Out-of-scope delays extend the schedule while active construction continues; construction slowdowns in response to external constraints extend the schedule by slowing or stopping construction activity.

Although specific causes of delay are numerous, the EPRI study shows that most significant out-of-scope delays can be traced to the nuclear design/regulatory process, and most construction slowdowns result from utility load-growth/financial problems. Further evidence of the problems with out-of-scope work in nuclear projects is provided by the foreign experience.

Extensive out-of-scope delays appear to be unique to the U.S. nuclear industry. U.S. coal-fired plants have experienced few out-of-scope delays over the last decade, yet they are owned, designed, and constructed by the same utilities, architect-engineers, and builders who construct nuclear plants. In Japan, France, and Sweden, where design has not changed frequently during construction, nuclear plants can be built in approximately 60 months. The lead time study concludes that the unique characteristic of

the U.S. nuclear industry—continuous design change that is applied retroactively to plants under construction—causes a large part of the out-of-scope delays.

Construction slowdowns for both coal-fired and nuclear plants are dominated by the owners' load-growth and financial problems. Other types of construction delays, including regulatory work stoppages, strikes, and delayed material deliveries, have had relatively minor effect on construction schedules. Construction slowdowns do not add permanently to lead times; as the utilities' construction programs become balanced with their revised load forecasts, these delays should abate.

Construction lead times

Project results show that coal-fired plant lead times have increased over the last decade, from 56 months for a 1968 plant to 68 months for a 1976 plant. It is not appropriate to extrapolate this lead time increase for future predictions because the factors that have caused these increases are temporary. The recent delays in coal-fired plant construction can be traced to load-growth and financial problems. Barring new, unforeseen problems, coal-fired plant construction lead times are likely to return to the historical average of four to five years as the gap between forecasted and actual load growth closes.

The forces extending nuclear plant construction lead times are more complex. For the plants started before 1972 (i.e., most of the plants that are now operating), construction schedules grew steadily from an average of 61 months for plants started in 1966 to 81 months for plants started in 1971. If this were a continuous trend, a plant started in 1978 would take 120 months to build. Indeed, some analysts have used such extrapolations to forecast lead times.

That extrapolation is incorrect for three reasons: The transitory effects of load-growth/financial problems are not likely to

continue; the increases in licensing and construction complexity resulting from the TMI-2 incident were much larger for plants nearing completion in 1979 than for plants in earlier construction stages in 1979; and for plants currently under construction, it is unclear whether the time-to-completion estimates given by the utilities anticipate out-of-scope delays during the remaining construction period. The EPRI study adjusted for these factors by segmenting the data and incorporating the effects of future expected out-of-scope delays.

Figure 1 shows that the elimination of these factors dramatically changes the expected lead times, particularly for plants started after 1972. For plants started during 1966–1971, lead times increased steadily. The plants started immediately following 1972 were hit very hard by industrywide out-of-scope delays, and there was a jump in lead times of about 30 months. The delays are now subsiding, and the plants started in the late 1970s should have shorter lead times than those started in the 1972–1974 period. Thus, the decline shown in Figure 1. However, for the plants started in 1976–1978, it is unclear whether the current lead time decline will continue or new problems will arise that produce another set of out-of-scope delays.

Derivation of lead time results

The results in Figure 1 are derived in two steps. First, the lead times are broken into component parts, as shown in Figure 2: initial estimate, out-of-scope delays, and construction slowdowns. Then, the additional anticipated out-of-scope delays are added to the lead time estimates for plants under construction. Figure 2 shows estimated lead times when construction begins and illustrates the delays that occur during construction.

Initial estimates: For the plants started before 1972, the lead time estimates made at the start of construction did not grow over time. After the Calvert Cliffs decision requiring an environmental impact statement, the initial estimates jumped about 20 months and have remained relatively flat since then.

Construction slowdowns: The impact of plant construction schedule extensions, cancellations, and abandonments on construction lead times is greatest for the plants that started most recently. Economics dictate that given a choice, a utility will delay a plant just begun rather than one near completion. Thus, the plants that received construction permits in the late 1970s have been more vulnerable to delays and cancellations than those ordered in the early 1970s.

Figure 1 Average duration of nuclear construction. Data are based on multiple variable regressions that control for architect-engineer experience, unit size, duplicate units, cooling towers, and units built in the Northeast region. The data are for units reporting load growth and financial delays of 13 months or less. Lead times for plants started in the 1966–1971 period showed a steady increase; industrywide out-of-scope delays caused a dramatic jump in lead time estimates for plants started in 1973, and the estimates have been declining steadily since 1973. At issue is whether this decline will continue for plants issued construction permits after 1978 or whether lead times will rise again according to the extrapolated pre-1971 rise.

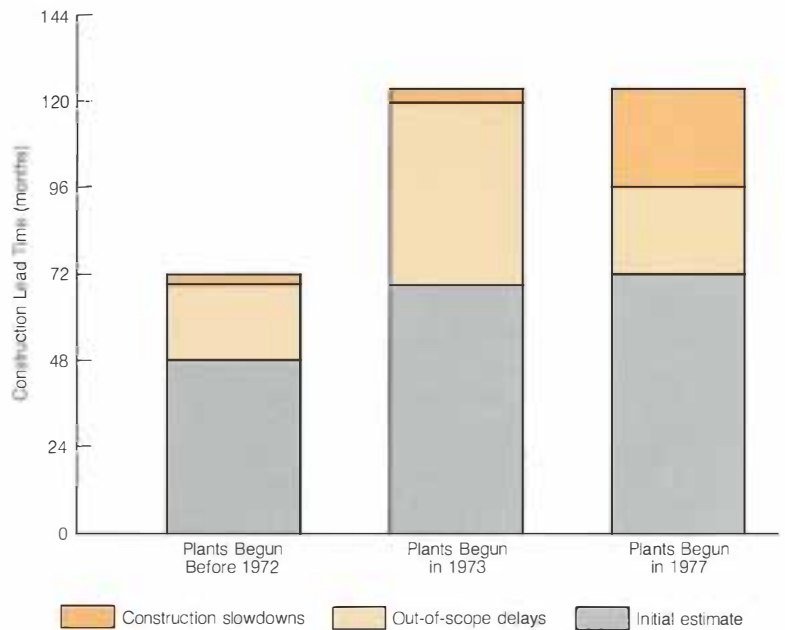
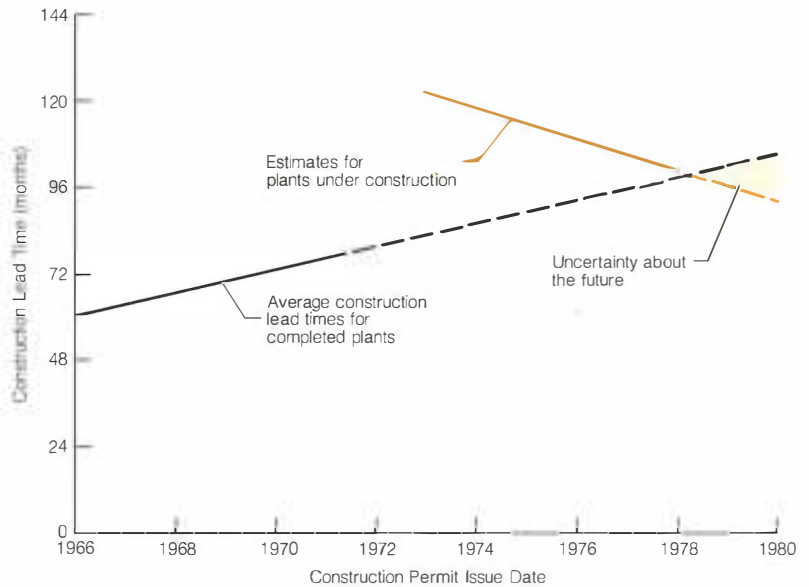


Figure 2 Components of lead times for nuclear plant construction. These components are based on the estimates at start of construction plus delays.

Out-of-scope work: Reported out-of-scope delays grew steadily for plants begun from 1966 through 1970, peaked for plants begun in 1972 following the Calvert Cliffs decision, and have declined for plants started since then. The increasing delays following the Calvert Cliffs period are closely correlated with the rapid buildup in Nuclear Regulatory Commission (NRC) regulations.

Time-to-completion model

The EPRI study documents that out-of-scope delays are declining and load-growth/financial delays are increasing for the later plants. Figure 2 shows the results based on the utilities' own time-to-completion estimates for plants under construction. However, because most of the plants started after 1972 are incomplete, the accuracy of the recent estimates is uncertain.

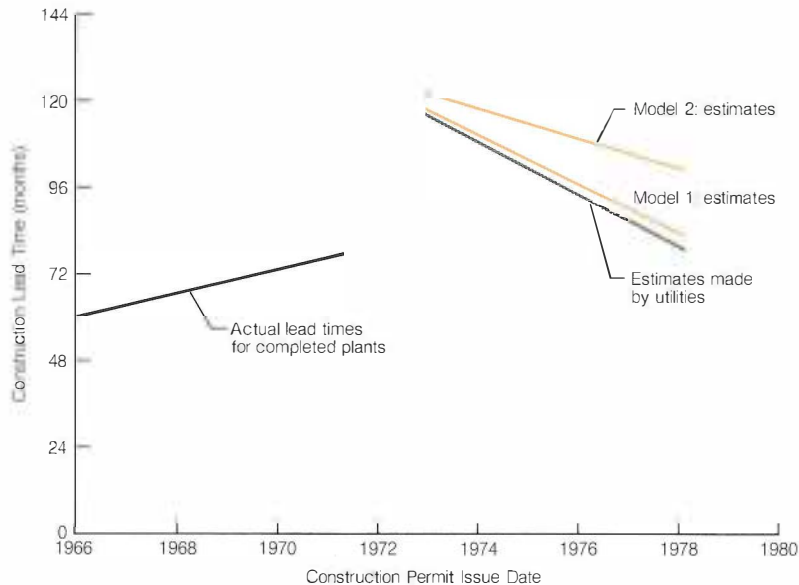
Because of this uncertainty, the EPRI study addressed the question of whether future out-of-scope delays should be incorporated into the estimates or whether the construction lead times will increase in response to future problems. To answer this question, a model was developed to estimate time to completion for plants under construction. A number of models were tried, and the EPRI analysis determined that the percentage of completion at a given point in the project is a good predictor of the remaining time to completion. Two curves were used. One compiled by William Lovelace at NRC used data for plants begun before 1972, and one compiled by Applied Decision Analysis, Inc., was based on plants begun after 1972.

The modeled results for plants under active construction are shown in Figure 3. The estimates based on pre-1972 data are quite similar to the utilities' own estimates. The estimated lead times based on post-1972 plants have shifted upward, but the pattern of declining lead times with later construction permits remains. Estimates of the time to completion made by the utilities will continue to slip, but average lead times are coming down over time.

Study results and future activities

The study has produced several conclusions that differ from previous lead time studies.

Figure 3 Average lead times to complete nuclear plants and estimates for those under construction. The trends are based on multiple variable regressions, as in Figure 1. Model 1 is based on pre-1972 data; Model 2 is based on post-1972 data. Note that the utilities' estimates and those based on Model 1 are close.



□ For nuclear plants currently under construction, lead times are declining, and quickly built plants are being completed in about eight years. The effects of TMI are subsiding, and the industry is learning to build plants that incorporate the design changes that occurred in the mid to late 1970s.

□ However, the underlying regulatory forces that caused lead times to increase at an average rate of about 5% /yr during the 1970s are still present.

□ If more plants are started in the 1980s, the key factors that affect the lead times of nuclear power plant construction are likely to be the degree to which design can be frozen during construction and the utilities' ability to manage system turnover and preoperational testing.

□ Coal-fired plant construction lead times have not increased except for schedule extensions caused by utility load-growth and financial problems.

A model that estimates construction lead time for nuclear plants has been formulated and its use indicates that estimates made by individual companies tend to be low. In addition, most of the uncertainty in nuclear projects occurs during the last third of construction. The estimating model is being finalized, and a final report will be published this year. Four types of follow-on activities are being considered: model improvement by developing better indicators of the percentage of plants complete; model use and data collection to analyze the nuclear deferral issue; cost analysis; model transferral to construction and planning groups. *Project Manager: Stephen Chapel*

R&D Status Report

ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Director

COMMERCIALIZING THE FUEL CELL

In the late 1970s major technological advances were made in developmental programs for phosphoric acid fuel cells. As fuel cell technology was approaching commercial readiness, it became extremely important that utilities interested in using fuel cell power plants familiarize themselves with the potential applications and benefits of this new electric generation technology. Motivated by this interest and by the opportunity to help establish realistic specifications for fuel cell power plants, a number of utilities, with EPRI's help, formed a group of potential users of fuel cells. This Fuel Cell Users Group (FCUG), now in existence for over two years, has become an important focal point in the commercialization of the fuel cell. The concept is a unique approach to the commercialization of a new technology and may well be the first of several similar groups.

FCUG was established in April 1980 with 37 charter members. The group now includes 57 utility members and 5 nonelectric utility associate members. The members are a diverse group of utilities located in over 30 states and in two foreign countries. They represent large and small, investor-owned, cooperative, and municipal utilities, as well as their respective trade associations.

A 15-member board of directors, consisting primarily of utility chief executive officers, provides overall policy and guidance. The Management Committee and the Executive Committee provide the planning and evaluation functions, while three technical subcommittees investigate issues involving system planning, fuels and fuel processing, and engineering and operation. Two other subcommittees communicate with members, initiate new-member programs, and interact with the federal government and utility, vendor, and environmental representatives to engender continued support for fuel cell programs.

Accomplishments

The main objective of FCUG is to expedite the commercialization of phosphoric acid fuel cell power plants (FCPPs) for electric utility application. In this pursuit, the activities of the group are fourfold.

- Assist the fuel cell developers in defining fuel cell system requirements and specifications for electric utility application and the market potential for fuel cell systems having these specifications

- Identify, sponsor, support, and participate in research, development, engineering, demonstration, and use of fuel cell energy systems

- Coordinate work and exchange information within the utility industry and with other public or private organizations concerned with the development and future use of fuel cells

- Encourage the development of fuel cells by interacting with the utility industry, government agencies, developers, and others

FCUG subcommittees are heavily involved in pursuing these activities. The Fuels and Fuel Processing Subcommittee, for example, has evaluated utility fuel scenarios and identified methane (from natural gas, synthetic natural gas, liquid natural gas, coal, biomass, and other unconventional resources) as the most likely near- to intermediate-term fuel for the fuel cell. Consequently, fuel cell power plants will be designed to use methane as the baseline fuel with liquid fuels considered as backup candidates.

The Systems Planning Subcommittee has developed specifications for a generic FCPP, identified important power plant characteristics and quantified their value in use, and reviewed with United Technologies Corp. and Westinghouse Electric Corp. (the suppliers) their respective FCPP specifications. In addition, the subcommittee has helped

develop two planning tools to determine potential FCPP applications within specific utility systems and has participated in EPRI workshops to promulgate these tools (RP1677-6).

The Engineering and Operations Subcommittee has determined that most of the licenses and permits needed for conventional power plants will also be required for FCPPs, but the time for issuance should be much less. In addition, it has identified the codes and standards that should be applied to FCPP manufacture and has recommended quality assurance guidelines that the manufacturers should follow.

By establishing a forum for discussion at its meetings and through written project reviews in its quarterly newsletter, FCUG provides an opportunity for its members to keep abreast of ongoing fuel cell development programs, such as the 4.5-MW demonstration in New York City (RP842). By acquainting its members with ongoing R&D activities, as well as R&D needs, the group provides an opportunity for individual utilities to sponsor fuel cell R&D activities that will complement the major research projects under way and provides a means to disseminate the results of such activities. Niagara Mohawk Power Corp., Northeast Utilities Service Co., and the Tennessee Valley Authority have sponsored such activities and still do. Southern California Edison Co., United Power Association, Basin Electric Power Cooperative, and the City of Santa Clara, California, are participating in the early stages of three projects relating to the integration of fuel cells with small commercial coal gasifiers (RP1041).

Under joint EPRI and FCUG sponsorship, seven meetings reviewing fuel cells and FCUG objectives were held across the country in 1981. Of over 300 utilities that were invited to participate, 108 attended and 18 subsequently joined FCUG (RP1677-5).

FCUG has worked with various Washington-based utility, manufacturer, and environ-

mental representatives to exchange information with government organizations on fuel cells. Working with these organizations, FCUG assisted in defining and justifying the 1982 Department of Energy fuel cell budget. Earlier this year the group stressed the need to maintain the 1983 DOE fuel cell budget at the 1982 level.

DOE has contracted with FCUG to evaluate the federal government's technical fuel cell program, and an FCUG steering committee was formed to guide this effort. Three of FCUG's subcommittees are reviewing DOE technology programs, and initial recommendations have been submitted to DOE. For the first time, utilities have had the opportunity to provide DOE with information so that it can better plan its activities to enhance and complement other fuel cell programs.

One of FCUG's initial activities was to work with the suppliers to determine commercial prototype power plant specifications for potential near-term buyers (RP1777-1). Now that preliminary specifications have been established (EM-2123) and suppliers better understand users' needs and are ready to negotiate sales of commercial prototype

units, FCUG is encouraging direct utility-supplier contacts.

As a group of potential FCPP users who may also represent an early market, FCUG could well play an important role in resolving the classic cost-economic dilemma faced by any new technology. That is, a manufacturer of a new product has to produce many units to spread nonrecurring costs over all units produced and to reduce total costs through improved design, manufacture, and installation. Although production costs (and presumably price) decline with increased units produced, initial units are relatively expensive.

Therefore, FCUG is exploring alternative funding, such as third-party financing. Such a concept uses established financial mechanisms, allows investors to receive tax benefits denied utilities, helps manufacturers produce multiple units for a price economically attractive to the third party, and allows several parties to share the risks of a new technology venture.

Future activities

Future FCUG activities include monitoring phosphoric acid fuel cell R&D, including the

4.5-MW demonstration and any commercial prototype installations. FCUG will serve as a clearing house for cost, installation, and performance data so that all FCUG members will have access to information important in the decision to purchase and install an early FCPP.

Guidelines for quality assurance in the installation, operation, and maintenance of FCPPs will be developed, and any utility purchasing a prototype or later unit will be encouraged to apply these guidelines to its installation. The financial benefits of FCPPs will be further analyzed and quantified by using utility-specific data and state-of-the-art corporate financial models (RP1677-6).

FCUG has solidified utility interest in FCPPs, provided utilities with realistic information on the heretofore unquantified benefits of fuel cells, and may provide the opportunity for many utilities to economically participate in the installation of initial FCPPs. Such a group of future users may well turn out to be a key factor in moving a successful technical development into a truly commercial utility environment. *Project Manager: David M. Rigney*

New Contracts

| Number | Title | Duration | Funding (\$000) | Contractor/ EPRI Project Manager | Number | Title | Duration | Funding (\$000) | Contractor/ EPRI Project Manager |
|-------------------------------|--|-----------|-----------------|--|--------------------------------|--|-----------|-----------------|---|
| Advanced Power Systems | | | | | Coal Combustion Systems | | | | |
| RP1599-1 | Fusion Status Report | 8 months | 40.0 | University of Wisconsin at Madison <i>K. Billman</i> | RP422-12 | CBI Capacitive Cooling System for ACT Facility | 6 months | 374.2 | Chicago Bridge & Iron Co. <i>J. Bartz</i> |
| RP1599-2 | Analysis of the Physics and Technological Status of Small Reactor Designs | 6 months | 54.8 | Jaycor <i>F. Scott</i> | RP899-2 | Fireside Consequences of Furnace Limestone Injection | 1 year | 539.1 | Combustion Engineering, Inc. <i>M. McElroy</i> |
| RP1657-3 | Evaluation of Critical Component Technologies for Combustion Turbine Catalytic Combustors | 1 year | 241.6 | Westinghouse Electric Corp. <i>L. Angello</i> | RP1180-15 | Preliminary Feasibility Analysis of Shop Assembly and Transport of Pressurized Fluidized-Bed Combustion Power Plants | 5 months | 27.8 | Foster Wheeler Development Corp. <i>S. Drenker</i> |
| RP1662-2 | Alternative Technological Pathways | 7 months | 100.0 | Westinghouse Electric Corp. <i>N. Amherd</i> | RP1260-31 | Demonstration of Equivalency for the Treatment of Metals-Cleaning Wastes in Ash Ponds | 11 months | 74.8 | Water Purification Associates <i>W. Chow</i> |
| RP1969-4 | Assessment of Technical Risks and R&D Requirements for a Magnetic Confinement Fusion Fuel System | 11 months | 252.1 | McDonnell Douglas Astronautics Co. <i>F. Scott</i> | RP1263-11 | State-of-the-Art Review: TCDD, TCDF, and Other Cyclic Hydrocarbons in Utility PCB Fluids | 7 months | 75.4 | SCS Engineers <i>R. Komai</i> |
| RP1974-4 | Hybrid Technical Integration and Program Planning | 10 months | 93.4 | Titan Systems, Inc. <i>N. Amherd</i> | RP1263-13 | Portable Ultraviolet Detection Kit for PCBs | 8 months | 40.0 | Monsanto Research Corp. <i>R. Komai</i> |
| RP1992-1 | Correlation of Reservoir Performance With Noncondensable Gas Fraction | 18 months | 62.2 | Stanford University <i>V. Roberts</i> | RP1265-12 | Failure Cause Analysis: Corrosion Fatigue of Boiler Waterwall Tubes | 8 months | 80.0 | Battelle, Columbus Laboratories <i>J. Dimmer</i> |
| RP2048-2 | Evaluation of Coating for Heat Exchange of Raw Syngas Coolers | 1 year | 174.7 | Combustion Engineering, Inc. <i>W. Bakker</i> | RP1266-31 | Fossil Plant Performance | 9 months | 122.9 | The S. M. Stoller Corp. <i>T. McCloskey</i> <i>D. Poole</i> |
| RP2112-3 | Evaluation of Coal Liquids as Utility Combustion Turbine Fuels | 17 months | 76.7 | Philadelphia Electric Co. <i>H. Schreiber</i> | RP1609-1 | Integrated Environmental Control Designs for Coal-Fired Power Plants | 15 months | 364.0 | Stearns-Roger Engineering Corp. <i>E. Cichanowicz</i> |
| RP2112-4 | Evaluation of Coal-Derived Liquids as Utility Boiler Fuel | 8 months | 233.0 | Energy and Environmental Research Corp. <i>H. Schreiber</i> | RP1860-3 | Assessment of Alternative Hardware Configurations for Atmospheric Fluidized-Bed Combustion Steam Generators | 10 months | 196.0 | Bechtel Group, Inc. <i>C. McGowin</i> |
| RP2112-5 | Evaluation of Coal Liquids as Utility Combustion Fuels | 13 months | 678.6 | Westinghouse Electric Corp. <i>H. Schreiber</i> | RP2154-01 | Retrofit NO _x Control Guidelines for Coal-Fired Utility Boilers | 11 months | 247.8 | KVB, Inc. <i>M. McElroy</i> |
| RP2146-2 | Liquid-Phase Methanol Synthesis Process Development | 2 years | 188.5 | University of Akron <i>N. Hertz</i> | | | | | |

| <i>Number</i> | <i>Title</i> | <i>Duration</i> | <i>Funding (\$000)</i> | <i>Contractor/ EPRI Project Manager</i> | <i>Number</i> | <i>Title</i> | <i>Duration</i> | <i>Funding (\$000)</i> | <i>Contractor/ EPRI Project Manager</i> |
|--|---|-----------------|------------------------|--|--|---|-----------------|------------------------|---|
| RP2190-1 | Design and Assessment of Refuse-Fired Cogeneration Facilities | 5 months | 69.4 | Nashville Electric Service <i>C. McGowin</i> | RP1908-3 | Effects of Acid Deposition on Crops | 25 months | 389.5 | University of California at Riverside <i>J. Huckabee</i> |
| Electrical Systems | | | | | RP1916-7 | Utility Sales Forecasting, Using State Space Models | 2 months | 29.5 | Scientific Systems, Inc. <i>L. Williams</i> |
| RP1473-4 | Demonstration of the 300-MVA Superconducting Generator | 57 months | 2579.0 | Tennessee Valley Authority <i>J. Edmonds</i> | RP2046-1 | Artificial Streams for Ecosystem Toxicity Studies | 3 years | 904.6 | Oregon State University <i>R. Brocksen</i> |
| RP1999-3 | Multiple Factorings in the Parallel Solution of Algebraic Equations | 14 months | 50.0 | Northwestern University <i>J. Lamont</i> | RP2141-2 | Decision Framework for Air Quality Standard Cost-Benefit Analysis | 5 months | 80.1 | Decision Focus, Inc. <i>D. Fromholzer</i> |
| RP2021-1 | Development of a Plan to Evaluate Distribution Automation | 17 months | 259.4 | General Electric Co. <i>W. Blair</i> | RP2152-1 | Targeting Utility Conservation Programs at Particular Locales Within a Service Territory | 6 months | 34.3 | R&C Enterprises, Ltd. <i>J. Wharton</i> |
| RP2131-2 | Development of Chemical Detection Method for PCBs in Oil | 1 year | 162.8 | Westinghouse Electric Corp. <i>V. Tahiliani</i> | RP2159-1 | Exposures to Carbon Monoxide | 6 months | 95.6 | Geomet Technologies, Inc. <i>C. Young</i> |
| RP7801-36 | Waltz Mill 230-kV XLPE Cable Installation | 6 months | 81.8 | Westinghouse Electric Corp. <i>J. Shimshock</i> | RP2173-1 | Effect of Chronic Exposures to Atmosphere of Sulfate Particles and Low Levels of Ozone or Nitrogen Dioxide on Chronic Respiratory Disease in Rats | 2 years | 100.9 | University of California at Davis <i>J. McCarroll</i> |
| Energy Analysis and Environment | | | | | Energy Management and Utilization | | | | |
| RP799-15 | Quality Control Evaluation | 7 months | 30.0 | The Aerospace Corp. <i>R. Kavet</i> | RP1275-15 | Feasibility Study of EPRI Participation in Pilot- and Commercial-Scale Evaluations of Electric Energy | 11 months | 138.5 | Bhat Technology International <i>L. Harry</i> |
| RP1050-8 | Fourth Symposium on Electric Utility Load Forecasting | 9 months | 33.6 | Applied Forecasting & Analysis, Inc. <i>L. Williams</i> | RP1968-1 | Industrial Load Management Demonstration—Definition Phase | 2 months | 29.4 | Applied Energy Systems, Inc. <i>R. Mauro</i> |
| RP1596-1 | Summary and Evaluation of EPRI Inhalation Toxicology Program | 1 year | 121.2 | Systems Applications, Inc. <i>J. McCarroll</i> | RP2034-4 | Monitoring Conservation in Electrically Heated Houses | 14 months | 150.0 | Princeton University <i>A. Lannus</i> |
| RP1630-23 | Source Emission Inventories for the Eastern and Western Regional Air Quality Studies | 30 months | 659.0 | Environmental Research & Technology, Inc. <i>R. Patterson</i> | RP2036-4 | Evaluation of Water Tank Stratification Techniques | 2 months | 27.5 | The University of New Mexico <i>V. Rabi</i> |
| RP1630-35 | Research Priorities and Criteria to Establish Factors That Govern Precipitation Chemistry | 8 months | 51.3 | State University of New York <i>P. Mueller</i> | | | | | |
| RP1826-8 | Consulting Services on Risk-Cost-Benefit of Regulated Toxic Substances | 7 months | 47.0 | The Detroit Edison Co. <i>R. Wyzga</i> | | | | | |

| <i>Number</i> | <i>Title</i> | <i>Duration</i> | <i>Funding (\$000)</i> | <i>Contractor/EPRI Project Manager</i> | <i>Number</i> | <i>Title</i> | <i>Duration</i> | <i>Funding (\$000)</i> | <i>Contractor/EPRI Project Manager</i> |
|----------------------|--|-----------------|------------------------|---|---------------|--|-----------------|------------------------|---|
| RP2037-2 | Technical Assistance in Improved Battery Charger Development | 7 months | 37.6 | Bevilacqua-Knight, Inc. <i>J. Mader</i> | RP1628-4 | Lifetime of PWR Control Materials | 38 months | 439.4 | Westinghouse Electric Corp. <i>D. Franklin</i> |
| Nuclear Power | | | | | RP1707-9 | Condition Monitoring of Nuclear Plant Electrical Equipment | 6 months | 68.7 | Nutech Engineers <i>G. Sliter</i> |
| RP510-2 | Fuel Performance | 41 months | 993.3 | General Electric Co. <i>D. Franklin</i> | RP1756-5 | Standardization of Re-qualification Requirements | 18 months | 92.1 | Teledyne Engineering Services <i>S. Tagart</i> |
| RP620-48 | LMFBR Consulting Agreement | 9 months | 38.1 | Pickard, Lowe and Garrick, Inc. <i>F. Arrotta</i> | RP1930-3 | Influence of Hydrogen Water Chemistry on Crack Growth | 13 months | 144.7 | General Electric Co. <i>M. Fox</i> |
| RP1163-7 | Modular Modeling System, Concept-Engineering Simulator | 5 months | 90.1 | Systems Control, Inc. <i>M. Divakaruni</i> | RP2006-8 | Prediction of Environmental Crack Growth in Nuclear Power Plant Components | 28 months | 247.0 | Framatome <i>J. Gilman</i> |
| RP1163-8 | Modular Modeling System, BWR Modules Development | 1 year | 165.1 | S. Levy, Inc. <i>M. Divakaruni</i> | RP2059-2 | Affiliation With a Sensor-Guided Robot Arc-Welding Program | 30 months | 30.0 | SRI International <i>W. Childs</i> |
| RP1324-7 | ABAQUS-EPGEN Analysis of High-Pressure Line Break Tests | 4 months | 27.3 | Nutech Engineers <i>H. Tang</i> | RP2062-6 | Stress Corrosion Cracking of Zircaloy Under Simulated Dry-Storage Conditions | 8 months | 43.7 | Atomic Energy of Canada Ltd. <i>A. Roberts</i> |
| RP1326-3 | Multidisciplinary Study of Radiation Damage | 6 months | 28.4 | Materials Research and Computer Simulation <i>T. Marston</i> | RP2122-5 | Experimental Study of Thermal Mixing Due to Cold Water Injection | 20 months | 542.4 | Creare, Inc. <i>J. Sursock</i> |
| RP1391-10 | Information System for Generation Availability, Summary | 3 months | 29.9 | TERA Corp. <i>C. Chan</i> | RP2166-2 | Field Evaluation of a Human Factors Maintainability Self-Review Methods Document | 18 months | 210.7 | Lockheed Missiles & Space Co., Inc. <i>H. Parris</i> |
| RP1393-5 | Containment Leak Rate Test Analyses | 3 months | 51.4 | Quadrex Corp. <i>T. Law</i> | RP2170-3 | A Systematic Human Error Application Procedure | 2 months | 178.9 | NUS Corp. <i>D. Worledge</i> |
| RP1544-3 | TMI-2 Mechanical Component Recovery Support | 12 months | 325.0 | GPU-Nuclear <i>A. Roberts</i> | RP2171-3 | Documentation Design for Probabilistic Risk Assessment | 11 months | 132.3 | Wood-Leaver & Associates, Inc. <i>D. Worledge</i> |
| RP1544-8 | Damage Assessment, TMI-2 Crane | 5 months | 28.6 | United States Crane, Inc. <i>K. Winkleback</i> | RP2177-1 | Thermal-Hydraulic Modeling of the Primary Coolant System Following a Severely Degraded Core Accident | 9 months | 147.2 | Science Applications, Inc. <i>O. Ozer</i> |
| RP1557-11 | Low-Level Radwaste, Volume Reduction Installations | 14 months | 81.4 | Burns and Roe, Inc. <i>M. Naughton</i> | RP2181-2 | Improved Stress Corrosion Resistance of High-Strength Age-Hardenable Ni-Cr-Fe Alloys | 3 years | 483.1 | Westinghouse Electric Corp. <i>A. McIlree</i> |
| RP1557-12 | Long-Range Low-Level Waste Disposal Costs | 12 months | 35.0 | Rogers & Associates Engineering Corp. <i>M. Naughton</i> | RP2182-2 | Evaluation of Extended Dry Storage of Spent Fuel on Reprocessing | 7 months | 60.0 | Allied-General Nuclear Services <i>R. Lambert</i> |
| RP1557-13 | Long-Term Low-Level Radwaste, Volume Reduction Strategies | 2 months | 65.9 | The Analytic Sciences Corp. <i>M. Naughton</i> | RP2186-1 | Application of Hard Surfacing Materials to Main Steam Isolation Valves | 2 months | 42.6 | ESD Corp. <i>B. Brooks</i> |
| RP1558-1 | Plant Fission Product Pathways | 13 months | 100.9 | Sargent & Lundy Engineers <i>M. Naughton</i> | RP2204-4 | Collection of Thermal-Hydraulic Experimental Data and Verification of GFLOW Code | 7 months | 36.4 | NUS Corp. <i>R. Lambert</i> |
| RP1559-1 | Fission Product and Chemical Monitoring | 18 months | 168.7 | Sargent & Lundy Engineers <i>M. Naughton</i> | | | | | |
| RP1561-3 | RELAP5/MOD1 Operational Transient, Comparative Calculations | 9 months | 53.0 | Intermountain Technologies Inc. <i>P. Bailey</i> | | | | | |

New Technical Reports

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

Inquiries on technical content may be directed to the EPRI project manager named at the end of each summary: 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. Research Reports Center will send a catalog and complete price list (including foreign prices) on request.

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Microfiche copies are available from National Technical Information Service, P.O. Box 1553, Springfield, Virginia 22151.

Cool Water Coal Gasification Program—First Annual Progress Report

AP-2487 Interim Report (RP1459); \$16.50

This reports the current status of the Cool Water Coal Gasification Program, conducted to design, build, and operate a 100-MW coal-based power plant to demonstrate new integrated gasification—combined-cycle technology at a commercial scale. The project's background and organizational structure are described; details of the planned facilities, design issues, plant operating and control requirements, and expected plant performance are reported; and project cost estimate and funding support, engineering work progress, and overall project status are indicated. The contractors are Bechtel Power Corp.; General Electric Co.; Southern California Edison Co.; and Texaco, Inc. *EPRI Project Manager: T. P. O'Shea*

Economics of the Texaco Gasification Process for Fuel Gas Production

AP-2488 Final Report (RP239); \$21.00

An economic evaluation of oxygen-blown, Texaco-based gasification of 11,000 t/d of Illinois No. 6 coal for clean, intermediate-Btu fuel gas production is reported. Two base-case gas cooling configurations—one involving saturated high-pressure steam generation and the other incorporating steam superheating capability in the gas cooling section—are examined. Substudies assessing the effects of the use of a gas recycle, change in the extent of sulfur removal, certain economies of scale, and changes in steam cycle conditions are summarized. The contractor is Fluor Engineers and Constructors, Inc. *EPRI Project Managers: M. J. Gluckman and A. E. Lewis*

Evaluation of Magnetic Confinement Fusion Engineering Opportunities on Existing and Planned Facilities

AP-2489 Final Report (RP1971-2); \$18.00

Examination of 24 representative reactor designs has identified 78 critical engineering data requirements and experiments important to the commercialization of magnetic confinement fusion. Preliminary plans for 10 experiments, including justification, expected results, schedule and milestones, and approximate costs, are given. The contractor is McDonnell Douglas Astronautics Co. *EPRI Project Manager: K. W. Billman*

Investigation of Combined-Cycle Steam Plant Problems

AP-2495 Final Report (RP1926); \$7.50

The operation and maintenance of gas turbine combined-cycle steam generators are reviewed. Feedwater cycles and auxiliary equipment are also discussed, and the results of on-site discussions with operating and maintenance personnel are presented. Actual problems encountered are delineated, and recommendations are given for improving operation of existing plants, for design of new plants, and for future research and development. The contractors are H. C. Crutchfield and Coecorp. *EPRI Project Managers: P. S. Zyguelbaum and R. L. Duncan*

Ceramic Materials for Fusion Reactors

AP-2515 Final Report (RP992); \$10.50

This report documents 1980 and 1981 project results that were obtained during a study of ceramic materials for fusion reactors. Analyses, mechanical property testing, and radiation damage studies

are emphasized. Siliconized silicon carbide is identified as the most promising low-activity ceramic for fusion first walls and blankets. The contractors are General Electric Co. and Rensselaer Polytechnic Institute. *EPRI Project Managers: K. W. Billman and W. T. Bakker*

Electric Utility Solar Energy Activities: 1982 Survey

AP-2516-SR Special Report; \$25.00

Survey results determining the scope of solar energy projects sponsored by U.S. electric utilities are summarized in brief descriptions of 943 projects conducted by 236 utilities. An index includes projects by category; a statistical summary; and lists of (1) participating utilities with information contacts and addresses, (2) utilities with projects organized by technology, (3) utilities organized by state, (4) available reports on utility-sponsored projects, and (5) projects with multiple utility participants. *EPRI Project Manager: E. A. DeMeo*

COAL COMBUSTION SYSTEMS

Effects of Process Water Selection on Lime/Limestone Flue Gas Desulfurization Chemistry

CS-2451 Final Report (TPS 80-730); \$13.50

Results of a planning study investigating power plant water management for plants operating with flue gas desulfurization (FGD) systems and use of wastewater in the FGD system are described. Calculations of FGD stream compositions and some operating conditions when using various combinations of coal, limestone, lime, and makeup wastewaters are detailed; two models used in the calculations are described; and the likely effects on operating conditions, scaling, and SO₂ removal of using these wastewaters are discussed. The contractor is Radian Corp. *EPRI Project Manager: D. A. Stewart*

Detailed Design for Incorporating CBI Capacitive Cooling System in the ACT Facility

CS-2463 Final Report (RP1260-27); Vol. 1, \$7.50; Vol. 2, \$7.50

This is a final design report of the capacitive cooling system to be added to the Advanced Concepts Test Facility, Bakersfield, California. Volume 1 is an executive summary. Volume 2 presents the design, detail engineering, and construction planning. The contractor is Chicago Bridge & Iron Co. *EPRI Project Manager: J. A. Bartz*

Construction and Operation of a Prototype Resox Plant in Conjunction With Bergbau-Forschung FGD System

CS-2467 Final Report (RP784-2); \$25.50

A project to evaluate a dry flue gas desulfurization system is described, and details are provided on 42-MW prototype test work on the Resox process and subsequent small pilot plant support work done at 1-MW scale. Mechanical performance aspects of the project are emphasized, and experience gained during the project is summarized. The contractors are Foster Wheeler Energy Corp.; Deutsche Babcock Ag; Bergbau-Forschung GmbH; and Steag Ag. *EPRI Project Manager: T. M. Morasky*

ADVANCED POWER SYSTEMS

Photovoltaic Balance-of-System Assessment

AP-2474 Final Report (RP1975-2); \$13.50

The balance-of-system status for photovoltaic power systems is assessed, including all sub-systems and components (except for cells and modules) that are needed for a fully functional power system. Array types for the central station, intermediate, and residential applications are evaluated; both active and passive cooling are considered for central station and intermediate applications; and battery energy storage is included as an option for intermediate and residential applications. The contractor is Bechtel Group, Inc. *EPRI Project Manager: R. W. Taylor*

Heat Transfer Characteristics of a Dry and Wet-Dry Advanced Condenser for Cooling Towers

CS-2476 Interim Report (RP422-2); \$7.50

This report presents the results of extensive bench-scale and pilot-scale testing of two types of advanced, air-cooled ammonia condensers for a phase-change wet-dry cooling system in electric power plants. One unit consists of Curtiss-Wright integral shaved-fin extruded aluminum tubing and is designed for dry operation; the other consists of a Hoterv aluminum plate fin-tube assembly and was tested in both wet and dry modes. The contractor is Union Carbide Corp. *EPRI Project Manager: J. A. Bartz*

Feasibility Study of Chemical Detoxification of PCB Capacitors

CS-2477 Final Report (RP1263-7); \$10.50

A preliminary study was conducted on chemical detoxification as it applies to polychlorinated biphenyls (PCBs) in capacitors. The results indicate that it may be possible to chemically destroy PCBs in capacitors. This report identifies questions that must be answered before the feasibility of such an operation can be determined, describes a research program to answer these questions, and explains federal requirements for alternatives to incineration. The contractor is Acurex Waste Technologies, Inc. *EPRI Project Manager: R. Y. Komai*

Combustion Processes in a Pulverized-Coal Combustor

CS-2490 Final Report (RP364-2); Vol. 1, \$16.50; Vol. 2, \$13.50; Vol. 3, \$16.50

This report presents research results obtained in a two-year, three-phase study of the mixing and kinetic processes in pulverized-coal combustor tests and pulverized-coal model development. Volume 1 details specific tasks, including pulverized-coal combustor tests and model development. Volume 2 presents a one-dimensional, steady-state model that describes pulverized-coal combustion and gasification. Coal reaction processes and gas-particle interactions are detailed, and descriptions of one-dimensional fluid mechanics and particle-particle, particle-wall radiation are included. User information is provided with a sample computation and a program listing. Volume 3 presents a two-dimensional, steady-state model that describes pulverized-coal combustion and gasification and is applicable to cylindrical axisymmetric systems. Modeling of the particle-phase and the gas-phase reactions is outlined, and user information is given with a sample computation and a program listing. The contractor is Brigham Young University. *EPRI Project Manager: J. P. Dimmer*

Monitoring Fixed FGD Sludge Landfill, Conesville, Ohio

CS-2498 Interim Report (RP1406-2); \$12.00

Results of the Phase 2, second interim activities for ongoing investigations of the Conversion Systems, Inc. (CSI) system for fixation-stabilization of flue gas desulfurization sludge are summarized. Phase 2 activities include (1) quarterly groundwater and runoff sampling to monitor for possible contamination, (2) annual sampling and testing of Poz-O-Tec landfill samples to compare with projected CSI physical characteristics, (3) observations of disposal operations to identify system utilization problems, and (4) assessment of overall

environmental acceptability. The contractor is Michael Baker, Jr., Inc. *EPRI Project Manager: D. M. Golden*

ELECTRICAL SYSTEMS

Basic Transformer Life Characteristics

EL-2443 Final Report (RP1289-1); Vol. 1, \$16.50; Vol. 2, \$7.50

Volume 1 gives a detailed account of the life-test procedure, the design of appropriate winding models, and the results of the first exploratory life tests performed on these models. A power transformer overload test procedure and a hot spot temperature sensor for transformer windings are evaluated, and essential thermal characteristics are identified. Volume 2 describes the results of a feasibility study on Luxtron Corp.'s Fluoroptic thermometer, which is a new optical primary measuring technique that may be adaptable for use as a conductor hot spot sensor for power transformers. Details are provided on dielectric and physical properties of jacket materials, immersion tests on optical fibers and complete probes in a transformer winding model, and recommendations for development of transformer applications. The contractor is General Electric Co. *EPRI Project Manager: B. S. Bernstein*

EPRI Generating-Unit Commitment and Production-Costing Program

EL-2455 Interim Report (RP1048-6); Vol. 1, \$13.50; Vol. 2, \$9.00

This report describes a generating-unit commitment and production-costing program developed for use in EPRI research projects and for application to utilities' planning and operations problems. Volume 1 is a user's guide, and Volume 2 is a programmer's guide. The contractor is Boeing Computer Services, Inc. *EPRI Project Manager: C. J. Frank*

Development of a Distribution Transformer Not Subject to Destructive Failure

EL-2484 Final Report (RP1143-1); \$12.00

This report describes the first phase of a project to investigate the substitution of inorganic high-temperature insulations for the oil-paper system in present transformer designs. Processing techniques that are necessary to apply various types of ceramic, glass, and other inorganic materials to a transformer are summarized, and a variety of design configurations for the transformer are presented. The contractor is McGraw-Edison Co. *EPRI Project Managers: J. W. Porter, R. J. Stanger, and R. S. Tackaberry*

ENERGY ANALYSIS AND ENVIRONMENT

Environmental and Socioeconomic Consequences of a Shortage in Installed Generating Capacity

EA-2462 Final Report (RP1374); \$37.50

This report presents an initial, major step in laying the foundation for a comprehensive, integrated

methodology to cost the environmental and socioeconomic consequences of electricity shortages. Focus is primarily on measuring the effects of electricity outages on certain classes of customers. Two models were developed to describe residential electricity consumption behavior and to calculate the costs of electricity outages. The contractors are Mathtech, Inc., and ICF, Inc. *EPRI Project Managers: A. N. Halter and R. E. Wyzga*

Approaches to Load Forecasting: Proceedings of the Third

EPRI Load-Forecasting Symposium

EA-2471 Proceedings (WS80-164); \$30.00

The papers included in this volume were presented at the Third EPRI Symposium on Electric Utility Load Forecasting held in Kansas City, Missouri, from March 25 to 27, 1981. Data problems, EPRI's efforts to enhance the flow of information on forecasting, forecasting sales, and hourly load forecasting are among the topics summarized. The contractor is Applied Forecasting & Analysis, Inc. *EPRI Project Manager: Edward Beardsworth*

Effects of Chlorine on Freshwater Fish Under Various Time and Chemical Conditions

EA-2481 Final Report (RP1435); \$9.00

Results are presented of laboratory bioassays conducted to determine the acute toxicity of monochloramine, dichloramine, hypochlorous acid, and hypochlorite ion to emerald shiners, channel catfish, and rainbow trout. Four exposure regimes used in the testing that are typical of chlorination schedules at operating steam electric power plants are described, time periods for exposure of the fish to the various chlorine species are indicated, and significant differences in toxicity among the various species are summarized. The contractor is University of Wisconsin at Milwaukee. *EPRI Project Managers: J. A. Huckabee and J. Z. Reynolds*

Marginal-Cost Pricing Under Uncertainty

EA-2491 Final Report (RP1220-5); \$10.50

This report presents a review of marginal-cost pricing methods, examines the impact of the incorporation of demand and cost uncertainty into marginal-cost pricing of electricity, and describes the development and application of a computer simulation model to a hypothetical utility for deterministic and uncertainty cases. A two-part rule for optimal pricing and optimal investment necessary for the efficient pricing of electricity is outlined. The contractor is Growth Systems Management, Inc. *EPRI Project Manager: A. N. Halter*

Workshop Measuring the Effects of Utility Conservation Programs

EA-2496 Proceedings (RP1050-2); \$19.50

This report contains the proceedings of the EPRI-sponsored workshop held February 11-12, 1982, in Columbus, Ohio, which focused on the design, implementation, and evaluation of customer-oriented energy conservation programs. Ten presentations by utility analysts on several aspects of residential energy conservation are included, and lessons learned with respect to program success (or failure) and evaluation approaches are addressed. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: Ahmad Faruqi*

Residential End-Use Energy Planning System (REEPS)

EA-2512 Final Report (RP1211-2); \$15.00

This report describes a forecasting model for evaluating impacts of various energy conservation measures. Development of REEPS, which involved estimating new models of consumer choice for energy-related decisions of appliance choice, operating efficiency, and utilization and integrating the choice models into a simulation system useful for forecasting, is outlined. An illustrative base case forecast of U.S. residential energy consumption to 1995 is included. The contractor is Cambridge Systematics, Inc. *EPRI Project Manager: S. D. Braithwaite*

ENERGY MANAGEMENT AND UTILIZATION

Preliminary Design Study of Compressed-Air Energy Storage in a Salt Dome

EM-2210 Final Report, Vol. 4 (RP1081-2); \$22.50

Volume 4 presents results based on measurements carried out at the Huntorf plant—a demonstration plant in operation. Other topics include selection of the plant heat cycle, plant performance characteristics, general plant arrangement, turbine and compressor control systems, electric system and instrumentation, potential effects on air quality, and potential effects of noise. The contractors are United Engineers & Constructors, Inc., and Middle South Services, Inc. *EPRI Project Manager: Antonio Ferreira*

Northern Climate Heat Pump Field Performance Evaluation

EM-2319 Final Report (RP789-1); \$10.50

This report presents the field data and related analysis for four residential and one commercial heat pump installation. Results are presented for an initial period of one year, covering both heating and cooling operations. Additional results reflecting changes in heat pump equipment and controls are presented for selected sites. The building structures, associated heat pumps, and the instrumentation system are described. Data summaries are presented that quantify actual operating characteristics and performance of these heat pumps in both heating and cooling modes of operation. The contractor is Carrier Corp. *EPRI Project Manager: Arvo Lannus*

Compressed-Air Energy Storage Preliminary Design and Site Development Program in an Aquifer

EM-2351 Final Report, Vol. 2 (RP1081-1); \$13.50

A study evaluated the performance of an aquifer compressed-air energy storage (CAES) system. Volume 2 presents the work performed by the five utility sponsors and provides an analysis of the benefits derived from the integration of a CAES facility with a hypothetical electrical network. The contractor is Public Service Co. of Indiana, Inc. *EPRI Project Manager: R. B. Schainker*

Cool Storage Instrumentation and Data Verification Program

EM-2485 Final Report (RP1089-1); \$25.50

Results are presented of a project to gather quantitative field performance data on operating sys-

tems and to develop guidelines for the use and application of cool storage systems. The data provided are intended to aid the electric utility industry in evaluating cool storage impacts on utility load factors, revenues, operating costs, and capacity requirements. R&D needs and opportunities are also identified. The contractor is Carrier Corp. *EPRI Project Managers: J. S. Brushwood and R. L. Mauro*

Development of Zinc Bromide Batteries for Stationary Energy Storage

EM-2497 Final Report (RP635-2); \$12.00

The feasibility of developing a zinc bromide storage battery system is addressed. The building and testing of a 10-kW, 80-kWh prototype battery of the bipolar design for 50 cycles are discussed. Details of (1) long-term studies on improvements in materials and processing and on life-cycling of small laboratory cells, and (2) a manufacturing cost study are provided. The contractor is Gould Inc. *EPRI Project Manager: W. C. Spindler*

NUCLEAR POWER

BWR Large-Break Simulation Tests

NP-1783 Interim Report, Vol. 1 (RP495-1); \$22.50

Volume 1 briefly describes the BWR system simulator, synthesizes the test results, and evaluates and analyzes the test data. Additional details and comprehensive sets of data are provided in the appendixes. The contractor is General Electric Co. *EPRI Project Manager: S. P. Kalra*

Disturbance Analysis and Surveillance System Scoping and Feasibility Study

NP-2240 Final Report (RP891-3); \$22.50

Results of a study to establish a disturbance analysis and surveillance system (DASS) for a plantwide availability and safety application are presented. DASS design concepts are applied to two trial examples; engineering, software, and hardware resources that are necessary to implement a plantwide system are estimated; and plans for a phased implementation of DASS are recommended. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: A. B. Long*

Metallurgical Investigation of Disk Cracking in the LP-2 Turbine at a Nuclear Power Station

NP-2269 Final Report (RP1398-7); \$13.50

An investigation of both rim and face cracking of low-pressure steam turbine disks is described. The general features of rim and face cracking are summarized; fractographic and metallographic examinations of the cracking are presented; and details on the deposit analyses, composition and microstructure of the disk material, and mechanical properties (e.g., tensile, impact, and hardness) are provided. The contractor is Southwest Research Institute. *EPRI Project Manager: M. J. Kolar*

Measurements and Comparisons of Generic BWR Main Steam Isolation Valves

NP-2381 Final Report, Vol. 1 (RP1389-1); \$7.50

Volume 1 describes the project tests, test valves and equipment, and field measurements; summarizes the salient test results and factors influencing these results; and presents the project conclusions and recommendations. The contractor is

General Electric Co. *EPRI Project Manager: B. P. Brooks*

Steam Turbine Disk Cracking Experience

NP-2429 Final Report, Vol. 2 (RP1398-5); \$9.00

Volume 2 summarizes the data discussed in detail in Volume 1 and the appendixes (Volumes 3–7). A summary of rotor stress analyses and discussions of relationships between disk cracking experience and a number of power plant systems and materials variables are also included. The contractor is Southwest Research Institute. *EPRI Project Manager: M. J. Kolar*

Diesel Generator Reliability at Nuclear Power Plants: Data and Preliminary Analysis

NP-2433 Interim Report (RP1233-11); \$15.00

A project was undertaken to collect and analyze data pertaining to diesel generator reliability in nuclear power plants. This report describes methods of deriving reliability estimates from data for use in probabilistic risk assessment and presents the results of applying these methods to data from 14 plants. A sampling theory approach and a Bayesian approach to failure probability estimation are compared and an analysis of diesel failures by subsystem, failure mode, and failure cause (based on data from Licensee Event Reports) is included. The contractor is Science Applications, Inc. *EPRI Project Manager: D. H. Worledge*

Normal and Refractory Concretes for LMFBR Applications

NP-2437 Final Report (RP1704-14, -19); Vol. 1, \$16.50; Vol. 2, \$9.00

This report describes an investigation of alternative castable construction materials that can be used at high temperatures and are compatible with sodium. Volume 1 presents an extensive survey of material properties information on portland cement concrete and various refractory concretes. Volume 2 presents an analysis of the high-temperature performance of various concretes, describes the more promising candidates for possible LMFBR applications, and recommends specific follow-on activities. The contractors are Northwestern University and Portland Cement Assoc. *EPRI Project Manager: Joseph Matte III*

Acoustic Monitoring of Power Plant Valves

NP-2444 Final Report (RP1246-1); \$25.50
NP-2444-SY Summary Report; \$7.50

These reports describe a project to monitor safety/relief valves in BWR plants and feedwater control valves in PWR plants. Acoustic monitoring of BWR safety/relief valves was evaluated as a means of identifying internal valve leakage. Hydrodynamic, vibration, control, and process signals from PWR feedwater control valves were monitored by a minicomputer-based surveillance system. The summary report briefly describes these efforts and the results; the final report presents complete documentation. The contractor is Technology for Energy Corp. *EPRI Project Manager: H. G. Shugars*

Evaluation of Secondary-System Oxygen Control in PWR Power Plants

NP-2448 Final Report (RPS104-2); \$13.50

Details are provided on the design of balance-of-plant systems and components in Europe and par-

ticularly in the USSR to minimize oxygen-induced corrosion in secondary systems of PWRs. Technical information on oxygen control in fossil and nuclear plants in the USSR is reviewed, water conditioning in condensate-feedwater systems is addressed, and the reduction of oxygen ingress is discussed in terms of various components. Recommendations for system protection against oxygen contamination and suggestions for monitoring and controlling oxygen content are included. The contractor is Burns and Roe, Inc., *EPRI Project Manager: R. L. Coit*

Comparison of Generic BWR MSIV Configurations

NP-2454 Final Report (RP1243-1); \$12.00

Results are presented of a comprehensive test and measurement program of the 26-inch Y-pattern main steam isolation valve (MSIV), and suggestions for appropriate corrective actions that are intended to improve the valve performance capability in achieving the seat leakage requirements of the local leak rate test are offered. Descriptions of the various tests performed on the MSIV are provided. The contractor is Alwood and Morrill Co., Inc. *EPRI Project Manager: B. P. Brooks*

Literature Survey, Numerical Examples, and Recommended Design Studies for Main Coolant Pumps

NP-2458 Final Report (TPS 79-776); \$15.00

This report presents an up-to-date literature survey, examples of calculations of seal forces or other pump properties, and recommendations for future work pertaining to primary coolant pumps and primary recirculating pumps in the nuclear power industry. Five main areas are covered: pump impeller forces, fluid annuli, bearings, seals, and rotor calculations. The contractor is Vibco Research Inc. *EPRI Project Manager: M. J. Kolar*

Statistical Methods for Establishing Safety System Margins

NP-2468 Final Report (RP1323-1); \$16.50

This report describes the development of a statistical methodology that provides a sound, realistic basis for the evaluation of nuclear reactor safety

system margins. Details are provided on an investigation of uncertainty components, advanced statistical techniques, state-of-the-art sampling techniques, and the development of new superior sampling techniques. Alternative methods of combining uncertainty components and the various merits of the components are included. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: J. D. E. Jeffries*

Growth and Stability of Stress Corrosion Cracks in Large-Diameter BWR Piping

NP-2472-SY Final Report (RPT118-1); Vol. 1, \$9.00; Vol. 2, \$28.50

Results of a research program conducted to evaluate the behavior of hypothetical stress corrosion cracks in large-diameter piping are reviewed. Details of the program, which included major tasks, a design margin assessment, an evaluation of crack growth and crack arrest, and development of a predictive model, are summarized. Volume 1 reports the research in a summary paper. Volume 2 contains the appendixes. The contractor is General Electric Co. *EPRI Project Manager: D. M. Norris*

Assessment of BWR Fuel Channel Lifetimes

NP-2483 Final Report (RP1943-1); \$15.00

Factors potentially limiting BWR fuel channel lifetimes are reviewed, including interaction with control rod blades, interaction with in-core instruments, bypass flow, and corrosion. Additional data and the nature of improved analytic methods needed to extend channel lifetimes are identified, and nonproprietary and channel deformation data are reviewed and analyzed. The contractor is Dominion Engineering, Inc. *EPRI Project Manager: H. Ocken*

Inhibition of Steam Condensate Corrosion of Copper-Based Alloys by Hydrazine

NP-2492 Final Report (RPS195-1); \$7.50

This report describes an experimental evaluation of the potential inhibiting effect of hydrazine on the corrosion of CDA 687 (aluminum brass) and CDA 706 (90 copper-10 nickel) in a simulated steam condensate containing ammonia under aerated and partially aerated conditions. Corro-

sion rates for both alloys under various conditions and the influence of hydrazine on those rates are presented. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: R. L. Coit*

Development of a Generic Procedure for Thermal Annealing an Embrittled Reactor Vessel, Using a Dry Annealing Method

NP-2493 Interim Report (RP1021-1); \$9.00

The feasibility and methodology for thermal annealing an embrittled reactor vessel are investigated. Assessment of the feasibility of an in situ thermal-annealing procedure that would maximize fracture toughness recovery, minimize reexposure sensitivity, and minimize reactor downtime is discussed. A conceptual thermal-annealing apparatus was developed, and a general thermal-annealing procedure was established. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: T. U. Marston*

Proceedings: Second International RETRAN Conference

NP-2494-SR Proceedings; \$54.00

This report contains the proceedings of the RETRAN Conference sponsored by EPRI and Energy Incorporated (April 26-28, 1982, San Diego, California), which focused on the exchange of information on the current use of the RETRAN code by various international licensees. Approximately 30 papers addressing the issues of RETRAN development, verification, and analysis of non-LWR systems; RETRAN analysis of PWRs; and RETRAN analysis of BWRs are included. *EPRI Project Manager: L. J. Agee*

Improved Electrodes for BWR In-Plant ECP Monitoring

NP-2524 Interim Report (RP706-1); \$9.00

This report details the design and development of an improved reference electrode suitable for long-term in-reactor electrochemical potential (ECP) measurements of type-304 stainless steel in a BWR primary water circuit. Data on the qualification of the electrodes in a laboratory test facility to 288°C are provided, and a comparison of ECP data obtained in this project with other ECP data is described. The contractor is NWT Corp. *EPRI Project Manager: M. J. Fox*

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