Fine-Tuning Large Hydro

MASTER FOR REFERENCE

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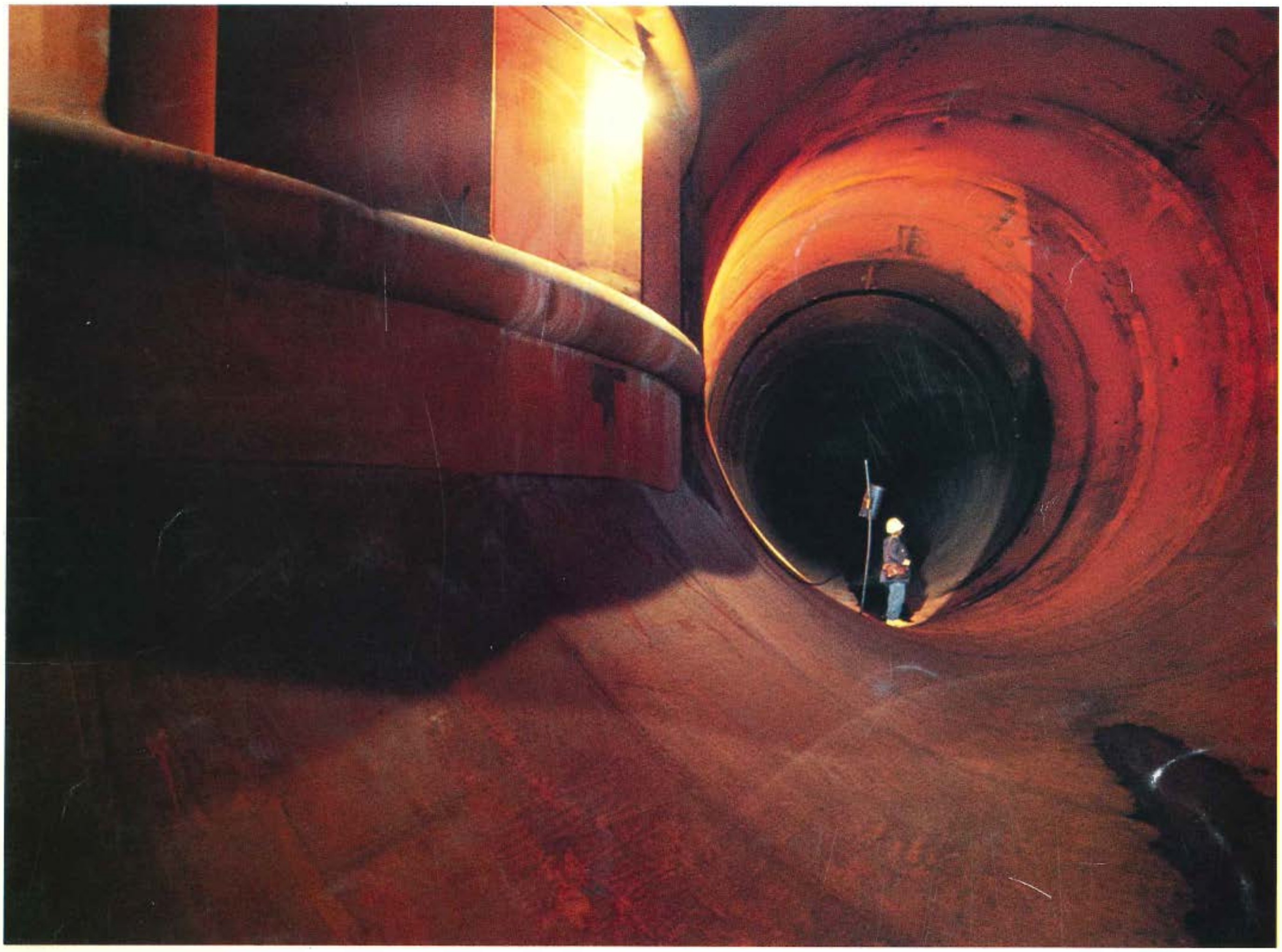

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EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution, and utilization.

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Cover: Hydro's immense proportions are dramatized by looking from inside the turbine's scroll case up the penstock at Hydro Québec's La Grande-4 powerhouse. Water channeled through the penstock enters the stay vanes at the upper left and rotates a water wheel to power the turbine. (Photo courtesy Bechtel Group, Inc.)

this change each issue

Maintaining a National Treasure

Editorial

Urged on by our utility advisers, EPRI initiated hydroelectric R&D three years ago amid intense interest and high expectations regarding small hydro. Since then, the escalating oil prices and concerns about oil availability that created the small-hydro renaissance have abated. This turnabout, along with the institutional impediments associated with building any new generating plant, has led to frustration for small-hydro developers and advocates. Although the enthusiasm for small hydro has diminished, it has had a significant impact. The public and key decision makers have learned about and gained an appreciation for one of North America's greatest treasures: the 150 GW of existing hydroelectric capacity.

It would take over a billion barrels of oil annually, worth some $30 billion, to replace the electric energy provided by North America's hydroelectric resource. In addition to being domestically produced, this energy is resistant to inflation, reliably generated, and inexhaustible. Yet we have taken this valuable resource for granted and have neglected to use it to fullest advantage. The neglect has taken many forms: modernization and improvements have been slow in coming; R&D has been virtually nonexistent; and for new plants, technology and know-how have not kept pace with demand. Hydropower has been tolerant—the only negative impacts have been unnecessary delays in the commercial operation of some new plants and minor performance deterioration at some older plants. These problems were caused, in part, by the depletion of limited financial resources before hydropower advancements were reached on the power producer's list of priorities. However, the renewed appreciation of hydropower has led to modest increases in funding for hydro advancements and research; one example is the creation of EPRI's hydro R&D program.

As explained in this month's lead article, EPRI's hydro program is aimed at helping the industry maintain and fine-tune North America's existing hydro capacity, both small and large. We expect this to result in an incremental improvement in hydro output. Unlike much of EPRI's more visible and exciting R&D, we are not fighting a crisis or expecting any research breakthroughs. Nonetheless, the benefits of incrementally improved hydro output are substantial—for the United States, $500 million a year.

Moreover, these benefits can easily be realized in the near term, since the R&D approach is straightforward. EPRI's hydro projects typically focus on facilitating the exchange of proven solutions to problems among North American hydropower producers, and on introducing proven diagnostic and monitoring instrumentation. Thus, with minor investment, hydropower producers should realize substantial benefits from the materials, equipment, and information resulting from our work.

A key to the successful use of EPRI R&D products and other hydropower advancements is a well-targeted information exchange and dissemination program. Our hydro advisers, representing hydropower producers that supply most of America's hydro capacity, have urged EPRI to take the leading role in this area. Existing mechanisms for hydro information exchange have been inadequate, largely because of the splintered nature of the hydropower community. We have developed simple and inexpensive solutions to this common but complex problem.

For example, we are helping to expand the magazine *Hydro Review* to cover all aspects of North American hydroelectric generation, not just small hydro. Technical papers and news articles will be contributed to the magazine by EPRI, the Canadian Electrical Association, and most of North America's hydropower producers. Engineering, equipment, operation and maintenance, environmental control, and R&D results will all be covered. Another information exchange mechanism is our series of annual hydro operation and maintenance conferences, which bring all segments of the industry together to share novel approaches to solving common problems. We think the magazine and conferences will reach the right people with the right information in a timely manner. Our goal is simple: helping these people maintain and improve a national treasure.

James R Birk

James R. Birk, Senior Program Manager
Energy Storage and Hydroelectric Generation
Energy Management and Utilization Division

Authors and Articles

Hydroelectric power leads the list of generation technologies in terms of performance efficiency and plant availability percentages. In **More Power From Hydro** (page 6), Nadine Lihach, the *Journal*'s senior feature writer, reviews some R&D steps that should squeeze out still a few more percentage points.

Charles Sullivan and James Birk, both of EPRI's Energy Management and Utilization Division, provided technical information. Sullivan joined the Institute's Nuclear Power Division in December 1974. He became a project manager for energy storage and hydroelectric generation in 1982. Before coming to EPRI, Sullivan spent two years with NRC's Reactor Systems Branch and six years at Lawrence Livermore Laboratory. He has a BS and an MS in mechanical engineering from Arizona State University.

Birk has been with EPRI since December 1973, first as a project manager for battery development and since 1980 as the manager of the Energy Storage and Hydroelectric Generation Program. From 1967 to 1973, he was a senior scientist on pollution control and advanced battery projects at Rockwell International Corp. Birk has BS and PhD degrees in chemistry from Iowa State University and Purdue University, respectively.

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Perhaps only a specialty technology for regional use or perhaps a sleeper among control alternatives for nationwide use in reducing SO_2 emissions, the injection of dry sorbents into power plant flue gas is a subject of close R&D scrutiny today. The pros and cons, knowns and unknowns, are considered in **Dry Capture of SO_2** (page 14), by *Journal* feature writer Taylor Moore, who had technical help from Robert Carr and Richard Hooper of EPRI's Coal Combustion Systems Division.

Carr has managed the Air Quality Control Program since April 1982. He came to EPRI in March 1974 after two years with KVB, Inc., as a test engineer and consultant to utilities on emission controls. During much of the last 10 years, his special interest has been the improvement and adaptation of fabric filtration for utility use. Carr began his work in emission measurement and analysis as a research assistant at the University of California at Berkeley, where he earned BS and MS degrees in mechanical engineering.

Richard Hooper, who joined the Air Quality Control Program as a project manager in July 1978, has been assigned to EPRI's Arapahoe Test Facility in Denver, Colorado, since May 1980. His special interest there is hands-on test work with detection, measurement, and control instrumentation. Hooper was formerly with Meteorology Research, Inc., for five years as a research scientist involved in meteorologic and environmental studies. Still earlier he worked for a subsidiary of Aerojet General Corp. in the development of devices for detecting biological warfare agents. Hooper has a BS in chemical engineering from California State Polytechnic University (Pomona).

■

Auxiliary motors, fans, and pumps in power plants are getting a new lease on life with the advent of electronic adjustable-speed drives. **Pacing Plant Motors for Energy Savings** (page 22), by Nadine Lihach, describes how these drives save energy and money for utilities, as well as how a few specific technical problems are being addressed by EPRI R&D. Ralph Ferraro furnished background information for the article.

Ferraro is technical manager for electric interface and control systems in the Energy Management and Utilization Division. He came to EPRI in December 1977 after four years at Bechtel Power Corp., where he became control systems supervisor for power plant projects. In the 1960s and early 1970s, Ferraro worked for three other companies in the design and production of power conversion and control systems, eventually serving as chief engineer in the Electro Dynamics Division of General Dynamics Corp. Ferraro is an electrical engineering graduate of the Newark College of Engineering.

■

Disposing of polychlorinated biphenyl (PCB) compounds is an arduous and expensive task. An important part of this effort is the detection of inadvertent PCB contamination in millions of utility transformers. Screening for PCBs is now faster, cheaper, and easier with the EPRI-sponsored test equipment reviewed in **PCB Detection in the Field** (page 29). Science writer John Douglas developed the article with the assistance of research managers from two EPRI divisions.

Vasu Tahiliani, a project manager in the Electrical Systems Division since January 1977, is concerned with transformers, capacitors, and other apparatus. He was formerly with I-T-E Imperial Corp. (now a part of Gould–Brown Boveri), where he worked for five years on the development of gas-insulated components. Still earlier he was a design engineer at McGraw-Edison Co. Tahiliani has BS and MS degrees in electrical engineering from the University of Baroda (India) and West Virginia University, respectively.

Ralph Komai, a project manager in the Coal Combustion Systems Division since May 1979, is concerned with hazardous waste disposal. He came to the division's Heat, Waste, and Water Management Program after five years with Southern California Edison Co., where he worked in licensing and compliance matters involving water supplies, pollution control equipment, air quality, and power process wastes. Earlier Komai spent two years as a chemistry editor for a publisher in Japan. A graduate in mathematics from Whittier College, he holds MS and PhD degrees in chemistry from the California Institute of Technology and the University of California at Riverside, respectively.

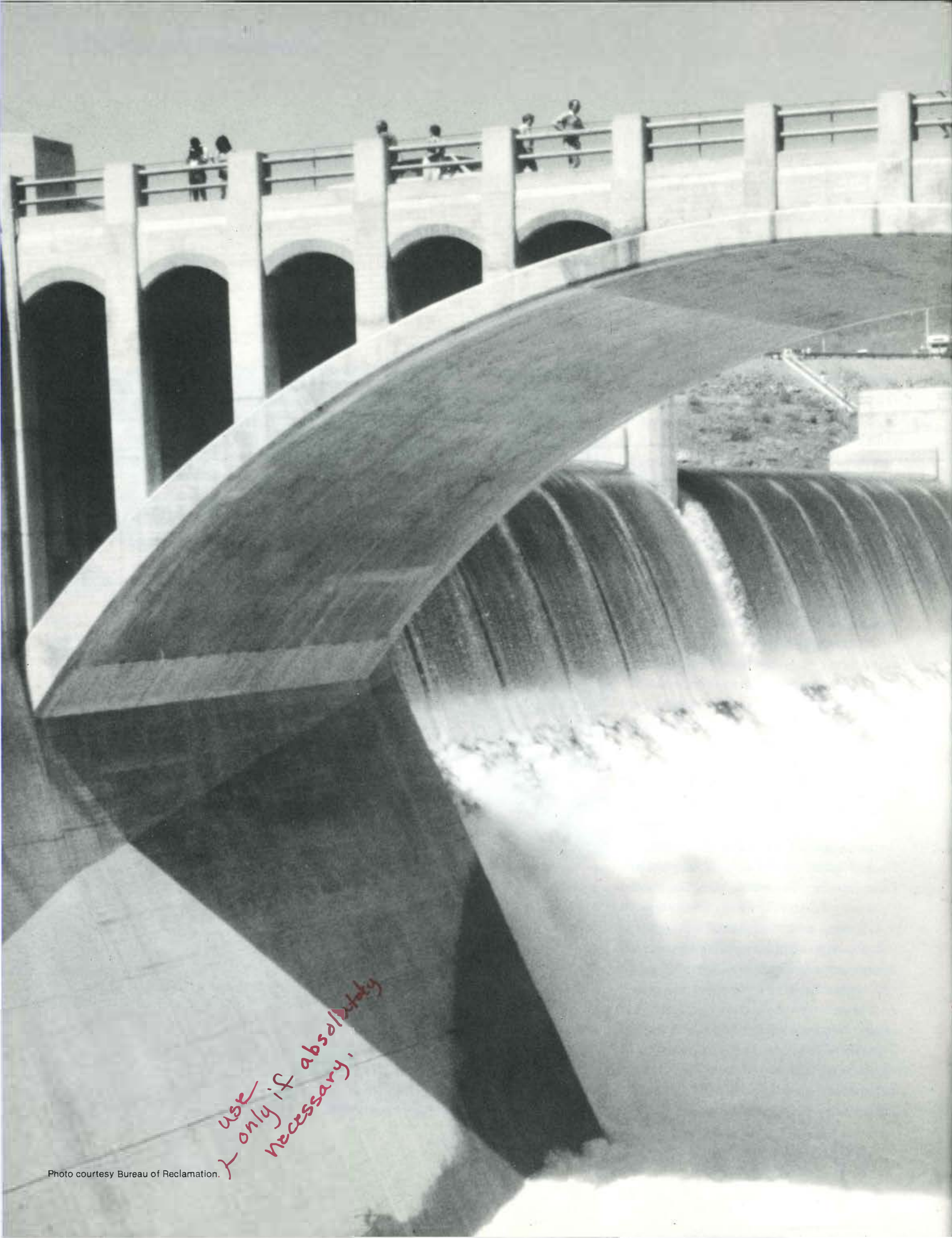
Carr Hooper

Ferraro

Birk

Sullivan

Tahiliani Komai



use only if absolutely necessary.

Photo courtesy Bureau of Reclamation.

MORE POWER FROM HYDRO

Utilities are striving to upgrade the already impressive performance of hydroelectric plants at a reasonable cost. Innovative approaches to operation and maintenance are springing up, but more effective channels for sharing technical information are needed.

Mention hydropower, and the mind leaps to stalwart dams and rugged turbines, brimming reservoirs and churning spillways. Large hydro plants are among the world's engineering triumphs, and their longtime reputation is one of solidity, strength, and unfailing readiness to serve. The reputation is well deserved: hydro produces some 309 billion kWh a year, one-seventh of the nation's electricity, and has a generating capacity of 80 GW, mostly large plants. Because of their relatively simple design, these plants boast an impressive 95% average availability, compared with about 80% for coal- and oil-fired plants, and about 70% for nuclear plants. Hydro plants have an equally impressive longevity: many have been delivering electricity steadily since they first went on-line 40, 50, even 70 years ago.

Strong incentives

But in today's tight economy, even the best performers must be pressed to do better, and hydro is no exception. The rapidly increasing cost of generating electricity, high financing costs for new power plants, and mounting difficulties in obtaining construction permits for plants are giving financially strapped utilities ever-stronger incentives for getting the most out of their existing units. Enhanced performance is particularly important for hydro plants because they generate some of the lowest-cost electricity of all.

Despite these incentives, performance improvements at hydro plants have not been a high priority for the utility industry. Hydro units have run almost trouble-free for decades, while oil plants contended with fuel limitations, coal plants encountered pollution problems, and nuclear plants raised safety and cost questions. With other, more pressing problems to solve, the industry has had little money to spare for improvements at hydro plants that are already doing a good job.

Still, because a plant does well doesn't mean it can't do better. Large hydro plants, for example, average only a couple of weeks out of service every year for routine maintenance, and several months every 15–30 years for major overhauls. Yet according to recent EPRI analysis, improvements in design, operation, and maintenance that increased availability at all hydro plants a mere 1% would save utilities $150 million a year. Efficiencies at hydro plants are also excellent, but again, analysis showed that improvements resulting in a half-percent increase in efficiency would save an estimated $75 million a year. These kinds of savings would seem to be well worth the relatively small R&D investment required. EPRI is convinced that important improvements are, in fact, within reach of slender R&D budgets.

Many of these improvements are already out there in the industry, according to Charles Sullivan, manager of hydro projects in EPRI's Energy Management and Utilization Division. Sullivan notes that in numerous cases, individual utilities and power producers have significantly reduced forced and scheduled outages by innovative diagnostic and repair techniques or have maintained high efficiencies by more careful operation.

But frequently, information about these improvements hasn't reached other utilities. Hydro plants are operated by all kinds of organizations, from federal agencies, to public agencies, to scores of privately owned utilities. There has been little opportunity for sharing technical information within the industry, particularly between public and private groups. Even when word of a better approach to a common hydro problem, such as premature generator failure or turbine cavitation, reaches power producers, they may not have sufficient information—or readily usable information—to put the new approach into practice.

To help utilities make the most of their large hydro plants and their equally large hydro experience, EPRI's EMU Division initiated a modest hydro research program in 1981. The program called for a judicious combination of conventional R&D and communication between hydro owners. The object was to find out what the industry already knew, research what they still needed to know, and share the information.

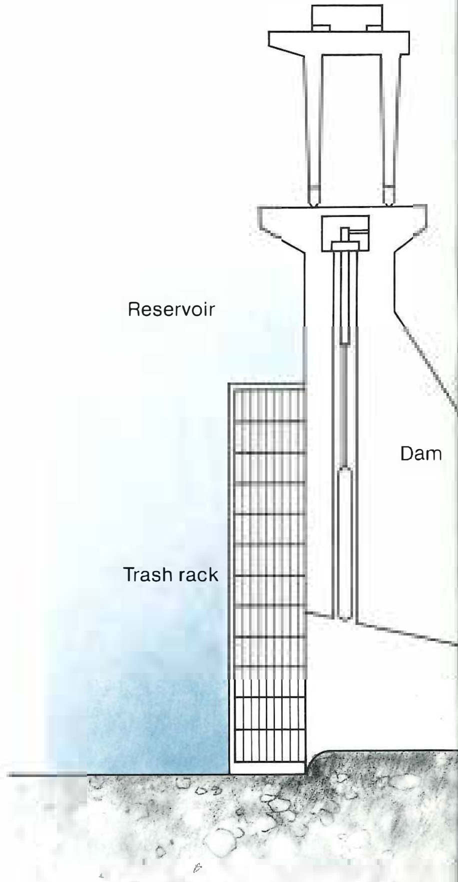
Forced outages first

EPRI began by soliciting utility industry feedback on what kinds of improvements would provide the most benefits for the least cost. Through a literature and field study by Motor-Columbus Consulting Engineers, Inc., and Black & Veatch Consulting Engineers, hydro owners ranked forced outages, scheduled outages, plant efficiency, and new equipment reliability as top candidates for improvement.

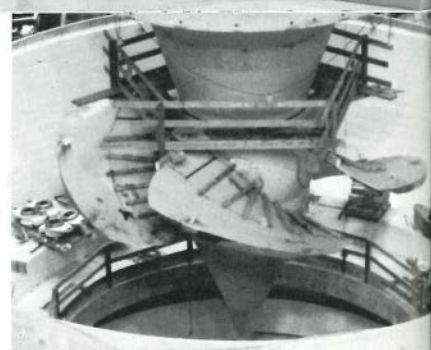
The frequency and duration of forced outages at hydro plants was a particular sore spot. Because few hydro operators conduct comprehensive diagnostic monitoring, failures can and do occur without warning. Unexpected outages can stretch anywhere from a few weeks to six months or even longer, consuming hundreds of thousands of dollars in labor and equipment and millions in replacement power. They are especially costly if a scheduled outage has just been completed or if necessary parts and skilled labor are unavailable.

One major instigator of forced outages is failure of generator stator windings, which results from excessive mechanical vibration or electrical corona discharge. The ensuing generator rewinding is a tedious process that takes an average of four to six months to accomplish. Years ago, winding failures were fairly infrequent: the asphalt-mica-insulated windings traditionally used in hydro generators could be counted on for 20 or more years of dependable operation.

Today's synthetic-insulated windings have better electrical characteristics and are more heat-resistant than their asphalt-mica predecessors, but they are also more brittle and therefore more susceptible to mechanical damage and pre-



Generators and turbines are the two largest pieces of hydro machinery in the plant. They require considerable time and work to disassemble and repair, so keeping them in good running order is a high priority.



(Photos courtesy U.S. Army Corps of Engineers)

How hydro can be improved

Steadfast hydro has been delivering electricity reliably for decades, but engineers are finding out that there is always room for improvement.

- Forced outages cost utilities dearly in labor, equipment, and replacement power. One of the major causes of forced outages is failed generator stator windings; rewinding takes four to six months of hard work. By monitoring windings more closely with diagnostic equipment, operators stand a better chance of detecting imminent failures and can schedule repairs for maximum convenience. Steady operation of the generator at low loads rather than abrupt start-stop action can also extend generator life.

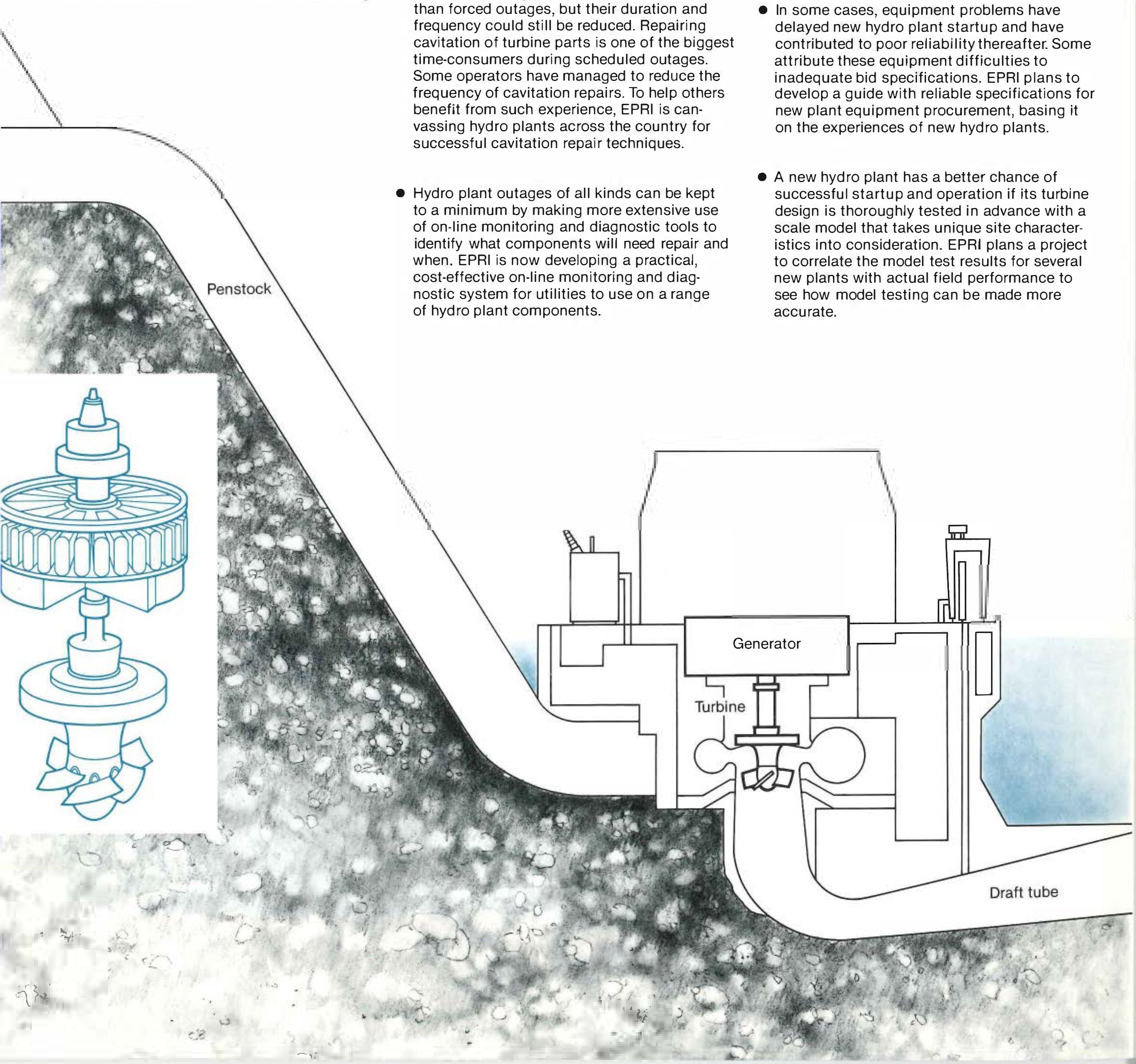
- Scheduled outages usually take less time than forced outages, but their duration and frequency could still be reduced. Repairing cavitation of turbine parts is one of the biggest time-consumers during scheduled outages. Some operators have managed to reduce the frequency of cavitation repairs. To help others benefit from such experience, EPRI is canvassing hydro plants across the country for successful cavitation repair techniques.

- Hydro plant outages of all kinds can be kept to a minimum by making more extensive use of on-line monitoring and diagnostic tools to identify what components will need repair and when. EPRI is now developing a practical, cost-effective on-line monitoring and diagnostic system for utilities to use on a range of hydro plant components.

- Plant efficiency is often taken for granted. Nevertheless, regular efficiency checks would permit detection of performance deterioration and would help hydro operators schedule maintenance and repair more effectively. EPRI is evaluating new ultrasonic systems for making quick, inexpensive checks on plant efficiency.

- In some cases, equipment problems have delayed new hydro plant startup and have contributed to poor reliability thereafter. Some attribute these equipment difficulties to inadequate bid specifications. EPRI plans to develop a guide with reliable specifications for new plant equipment procurement, basing it on the experiences of new hydro plants.

- A new hydro plant has a better chance of successful startup and operation if its turbine design is thoroughly tested in advance with a scale model that takes unique site characteristics into consideration. EPRI plans a project to correlate the model test results for several new plants with actual field performance to see how model testing can be made more accurate.



mature failure. If these windings are not installed precisely and secured tightly in their proper slots in the generator, the resulting vibration and corona discharge can seriously damage them and ultimately result in damage to the generator's iron core as well. When damaged windings are replaced in the harried atmosphere of a forced outage, improper rewinding can begin the problem all over again, and in several cases, rewindings have failed within a year or two of installation.

EPRI studies suggest that prevention may be the best way for plant personnel to extend the useful life of windings, minimize rewinding downtime, and give new windings a better survival rate. Dielectric measurements taken on windings at regular intervals can keep operators apprised of performance trends. These measurements will indicate when windings should be replaced, and utility managers can schedule an appropriate outage and plan to have necessary equipment and trained personnel available. When winding deterioration has been detected, operating the generator at a low load instead of repeatedly stopping and starting it may extend insulation life.

Planning time out

Routine scheduled outages at hydro plants are usually less costly than forced outages. They are planned as carefully as possible, so that the plant is down when it is least needed and so spare parts, necessary equipment, and appropriate personnel are all on hand. Hydro plants are usually down only one to three weeks every year or two for minor scheduled maintenance. During these outages, the hydromachinery is dismantled as necessary and essential parts are cleaned, inspected, repaired, replaced, or adjusted. By keeping a plant properly maintained, scheduled outages ultimately reduce the frequency and duration of the much more serious forced outages.

But even scheduled outages can take more time and trouble than necessary. One particular problem that can singlehandedly increase both the duration and frequency of scheduled outages is cavitation of turbine parts. Cavitation is the pitting of metal parts that results from the implosive collapse of water vapor bubbles, and it is complicated and costly to correct. Workers have to clamber into the turbine, grind down the blistered metal, weld the area repeatedly, and then grind it again to perfect contours. The painstaking process can add weeks to an outage. Furthermore, if inadequate repair methods are used, cavitation may worsen with time, and outages may have to be scheduled with increasing frequency.

A few hydropower producers have managed to reduce the frequency of cavitation repairs to once every four years or even longer, which suggests that certain maintenance approaches work better than others. However, successful procedures have been developed on a plant-by-plant basis and have not been standardized and made available to the industry at large. Through Acres American, Inc., EPRI is surveying the various cavitation repair techniques used throughout the hydro industry. A detailed report on how best to repair cavitation will be available by 1985.

The time between scheduled outages can also be extended by making better use of diagnostic tools for on-the-spot assessment of equipment damage. Diagnostic systems can tell operators if and when a component will require repair. But some improvements have to be made. For example, monitoring techniques are available for detecting cavitation damage, but these techniques only confirm the presence of cavitation, not indicate its extent. Advanced techniques and equipment that provide specifics on damage rate and extent could help reduce the frequency of repairs.

Through a contract with Ontario Hydro, EPRI is now developing a practical, cost-effective, on-line monitoring and diagnostic system for utilities to use in identifying maintenance and repair needs at hydro plants. The full system will be able to detect incipient equipment failure and predict how much time is left before an outage is absolutely necessary. The goal is to perform necessary maintenance at the most opportune time. The entire package will be demonstrated on hydro plants by 1985 and should be commercially available in 1986. Complete system specifications and a procedures manual will be made available to utilities so they can take full advantage of this package.

Eye on efficiency

Keeping outages to a minimum is one way of improving hydro plant performance; so is maximizing the efficiency of these plants while they are actually on-line. Many hydro operators take plant efficiencies for granted because they are so high, often anywhere from 83 to 93%. At some plants, efficiency is only checked once, when the unit first goes on-line.

Regular efficiency checks over the life of the plant would enable hydro operators to detect deterioration of performance, which, in turn, would enable them to schedule maintenance and repair more effectively and even help identify the causes of lowered performance. But the standard penstock flow measurement techniques used for assessing hydro plant performance are too costly and time-consuming to use on a regular basis; furthermore, no power is produced while a unit is being tested.

Quick, inexpensive flow rate measurements are necessary to keep frequent tabs on hydro efficiency. Such techniques are available, but they have not been standardized to the industry's satisfaction. New systems that use ultrasonics to continuously monitor flow without interfering with plant operation have been evaluated by EPRI and B.C. Hydro at the Kootenay Canal hydro site in British Columbia. These systems will also be tested at two other sites—the Bureau of Reclamation's Grand Coulee plant in Washington and TVA's Raccoon Mountain in Tennessee—later this

Box

MAKING SMALL HYDRO SUCCEED

Most of the best sites for large conventional hydro plants already have powerhouses on them, but there are numerous streams and rivers on which small hydro units with capacities ranging from less than 1 MW to as much as 15 or 20 MW could be built. Before the energy upheavals of the past decade, most of these smaller sites were too uneconomical to develop. But as energy prices rose, the old millstream came to be looked upon less as postcard scenery and more as potential electricity. Federal and state tax incentives beckoned, and hydro developers followed.

Many developers assumed that small hydro plants would be easy to bring on-line. The designs were uncomplicated, hydromachinery was commercially available, and there were no fuel bills to pay. But although flurries of permit applications were filed with the Federal Energy Regulatory Commission, many small-hydro projects never made it to startup. These small projects were waylaid by licensing difficulties, high capital costs, environmental concerns, and financing squeezes. Developers who managed to pull their projects through often found that their generating costs were higher than they had anticipated and their profits lower.

The incentives for developing small hydro plants remain, but the likelihood of success is greater if developers are fully aware of the right approaches — and know enough to avoid the wrong ones. EPRI and DOE are now documenting the successes and failures of various approaches used in DOE's small-hydro program, begun in 1977 to promote small-hydro development; International Engineering Co., Inc., is the contractor. The data base includes 214 feasibility studies, 42 licensing activities, and 20 field tests. A guide with complete recommendations for developing small-hydro sites, covering everything from preliminary studies to final operation and maintenance, will be available by the end of this year.

One of the biggest barriers to small-hydro development is high capital cost. Of an estimated 8700 MW of undeveloped small-hydro capacity, only about 20–25% can be economically developed with the technology available today. Developers commonly tackle small-hydro projects as if they were large projects, preparing a unique design for each plant and even commissioning certain custom-made equipment. This approach may be acceptable at large plants, but small plants just don't have the budget for it.

Small hydro's capital costs may be reduced by using standardized, modular equipment packages for plant construction. The package can include standard industrial vertical pumps to be operated in reverse as turbines; pumps as turbines, or PATs, are simpler to install, operate, and maintain than custom-made turbines. They can also be mass-produced and so cost less than the usual hydroturbines.

A standardized equipment package might also include standard induction motors for generators and standard prefabricated metal buildings for powerhouse superstructures. Siphoning penstocks, which go over the top of an existing dam rather than through it, eliminating costly civil engineering work, could round out the modular package.

EPRI and contractor Acres American, Inc., recently evaluated a standardized, modular design concept for small hydro, assessing cost savings, design, expected performance, and potential risks. The results showed that substantial cost savings were possible when siphoning penstocks and PATs were used in appropriate situations. Details will be available in a four-volume report (including an applications manual) due out early this year.

Ultimately, small hydro may contribute only 8 or 9 additional GW of capacity to the nation's energy reserves, but in times when every bit of inexpensive energy counts, even small contributions cannot be overlooked. EPRI's R&D to increase the potential of small hydro promises to have an excellent payback. □

HYDRO: A Diversity of Organizations and Objectives

Organization	Number of Plants	Total Capacity (MW)	Primary Objectives*	Member, EPRI Hydro Advisory Group
U.S. Army Corps of Engineers	70	19,500	Electric power, navigation, water supply	Yes
U.S. Department of the Interior, Bureau of Reclamation	50	12,500	Flood control, irrigation, electric power	Yes
Tennessee Valley Authority	30	4,800	Flood control, navigation, electric power	No
Other federal agencies (e.g., Alaska Power Administration)	10	120	Electric power	Yes
Nonfederal public agencies (e.g., state and municipal utilities, irrigation districts)	300	16,000	Depends on agency	Yes
Rural cooperatives	20	80	Electric power, recreation	Yes
Private utilities	650	24,500	Electric power, recreation	Yes
Private nonutilities (investors, industry, and individuals)	350	1,500	Electric power	No

*Additional objectives include water quality improvement, fish and wildlife enhancement, and vegetation and mosquito control.

The generator hall at the U.S. Army Corps of Engineers' John Day Dam, The Dalles, Oregon, houses 16 turbine generator units with a total capacity of 2200 MW.

spring. So far, these simplified techniques seem to be every bit as good as conventional methods; final results will be published beginning in mid 1984.

Good starts for new plants

Improved efficiency and reduced outages may be the best ways of getting more out of existing plants, but new hydro plants present some special concerns of their own. In some cases, brand-new plants have been delayed in getting on-line and dogged by poor reliability because of new equipment that just won't function correctly. Average availability for some new plants has been less than 50%, possibly as low as 30%. Some plants have taken several years instead of the usual several months to come up to full performance. This costs utilities dearly: a one-year delay in commercial operation and a 30% reduction in availability for an additional year would cost the industry some $200 million annually, assuming an annual expansion of 1000 MW of hydro capacity.

Some hydro experts maintain that problems with new equipment result, in part, from inadequate equipment specifications in bids and an overemphasis on cost in the contract award process. When a utility commissions a new plant, the specifications its engineers select may not result in expected plant performance. Utilities may also be under pressure to award equipment and installation contracts to the lowest bidders, whose bids may barely meet minimum performance requirements. Relatively inexperienced labor may also be employed to field-assemble and install critical hydro components like generators, resulting in such problems as generator winding failures.

Guidelines for hydro plant construction and equipment procurement would help utilities make sure they are getting the hydro plants they need, and EPRI plans to develop such guidelines over the next few years on the basis of experiences at new hydro plants across the country.

The likelihood of successful new hydro plant startup and operation can also be increased by thoroughly testing turbine design with a scale model. Models are commonly used by designers to tailor large new hydro plants to individual site characteristics; properly applied, they can help eliminate or mitigate many of the problems associated with vibration, cavitation, hydraulic thrust, and pressure pulsation. EPRI plans a project to correlate the model test results of several new plants with actual field performance to see how model testing can be made more accurate.

Passing the word

Because EPRI's hydro projects concentrate on specific areas of current concern and because a large part of the effort involves collecting existing industry experience, results will be ready for the industry to use fairly soon. But it will take more than rounding up industry experience and applying a modest amount of R&D to bring about significant improvements at hydro plants. "We want to make sure that the results of these projects reach the thousands of people in hydro planning, design, construction, operation, and maintenance—people from federal agencies, nonfederal public utilities, private utilities, and third-party developers," explains James Birk, manager of EPRI's hydro program.

Word on how to make hydro better is already being passed along through EPRI-sponsored national operation and maintenance workshops. These workshops give both public and private hydropower producers the chance to exchange up-to-date information and techniques for effective operation and maintenance of their plants. Two workshops have already been held, drawing nearly 300 attendees representing over 100 hydropower producers. For many participants, the workshops were a unique opportunity to hear firsthand what the rest of the hydro industry was up to.

A plan to reach an even wider hydro audience begins this year. EPRI is collaborating with an established magazine, *Hydro Review*, to publish articles on the latest in hydro improvement techniques. The Boston-based quarterly formerly covered only small-hydro developments, but will expand its coverage with EPRI's assistance. Over the next three years, EPRI will supply *Hydro Review* with some 45 technical articles on both large and small hydro; the joint effort will begin with the magazine's summer 1984 issue. Birk is now working to extend *Hydro Review*'s circulation list to include large hydropower producers, both public and private.

For a technology that was considered mature 40 or more years ago, hydro is turning out to have unanticipated potential. Over the next few years, expect to see fewer and shorter outages, better efficiencies, higher availabilities, improved new plant reliability, and all-around better performance, to the benefit of hydro utilities and the customers they serve.

Further reading

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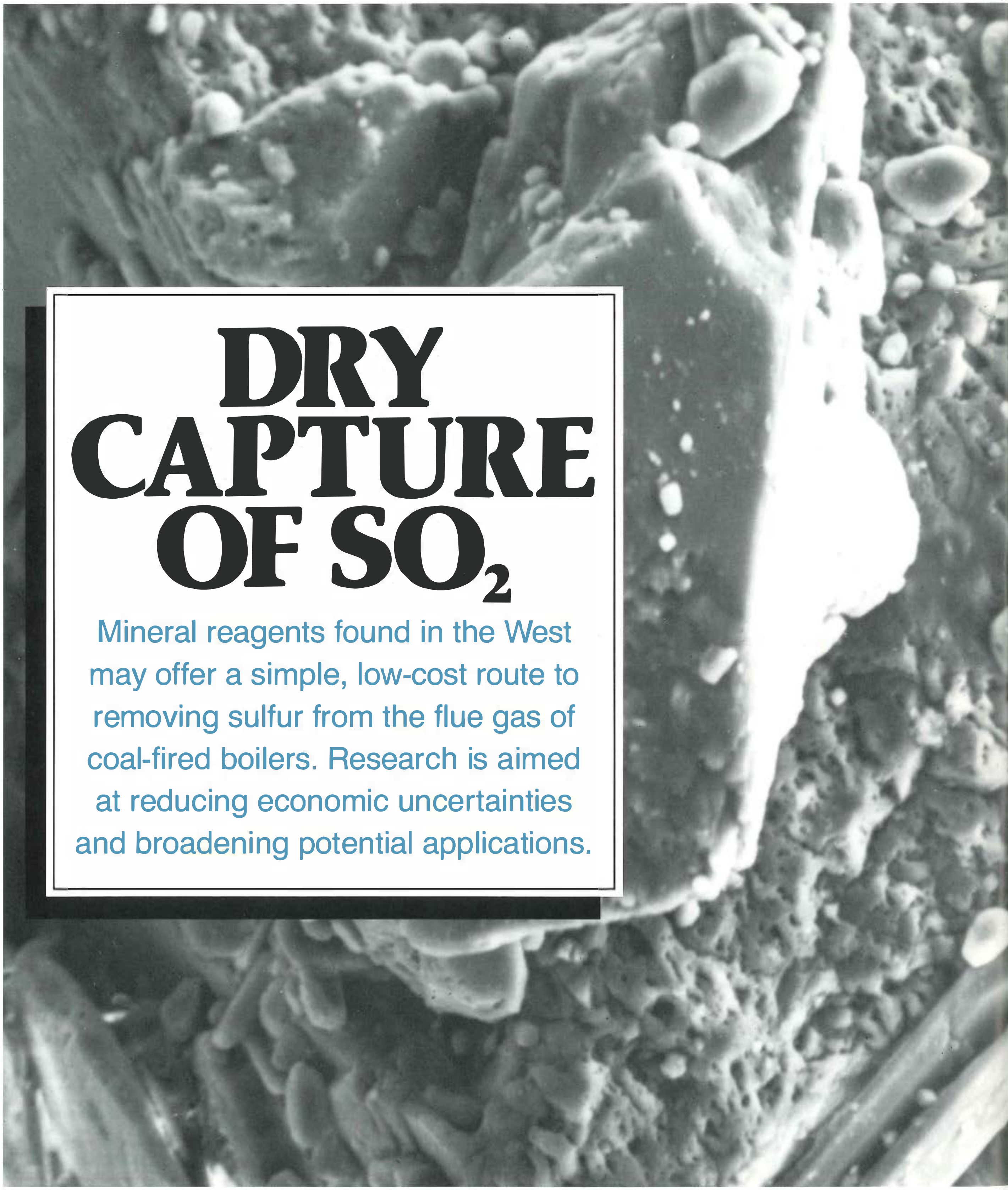
New York State Energy Research and Development Authority. *Modular Small Hydro Configuration*. September 1981. ERDA Report 81-16.

Oak Ridge National Laboratory. Environmental Sciences Division. *Analysis of Environmental Issues Related to Small-Scale Hydroelectric Development*. Vol. 6, *Dissolved-Oxygen Concentrations Below Operating Dams*. January 1982. ORNL/TM-7887.

U.S. Army Corps of Engineers. *National Hydroelectric Power Resources Study*. Vol. 9, *Potential for Increasing the Output of Existing Hydroelectric Plants*. July 1981. IWR-82-H-9.

U.S. Department of the Interior. Bureau of Reclamation. *Report on Assessment of Low-Head Hydroelectric Sites in the Western States: Methodology and Summary*. March 1982.

This article was written by Nadine Lihach. Technical background information was provided by James Birk and Charles Sullivan, Energy Management and Utilization Division.



DRY CAPTURE OF SO_2

Mineral reagents found in the West may offer a simple, low-cost route to removing sulfur from the flue gas of coal-fired boilers. Research is aimed at reducing economic uncertainties and broadening potential applications.

Coal-fired electric generating plants soon may literally take a powder to control sulfur emissions. In a search for least-cost paths to compliance with tightening air quality regulations, injection of dry sorbents into the flue gas stream to remove sulfur oxides is emerging as an economically attractive option, particularly for plants firing low-sulfur coal.

Two naturally occurring sodium-based minerals—nahcolite and trona—are currently the compounds of interest as dry sorbents. The basic process is surprisingly straightforward: powdered sorbent is fed into a generating plant's flue gas duct downstream of the air heater and upstream of a baghouse. Sulfur dioxide (SO_2) reacts with the reagent in the flue gas and on the surface of the bags. Spent reagent cake—containing mostly fly ash and sulfur compounds—is removed as dry waste with normal bag cleaning. In contrast to conventional wet scrubbing, the process needs no water.

Dry sorbent injection is a much simpler process than wet scrubbing, according to Robert Carr, manager of EPRI's Air Quality Control Program in the Coal Combustion Systems Division. "You pulverize the sorbent, blow it into the ductwork, it collects in the baghouse with the fly ash, and you remove SO_2 with no real impact on the baghouse. In a cooperative effort with Public Service Co. of Colorado, we've demonstrated that it works. We can get 70–80% sulfur removal right now on low-sulfur coal."

Recent investigations have shed new light on the chemistry and economics of this technique. Despite its low capital cost and mechanical simplicity, however, the process does have its drawbacks. The availability and cost of transporting sorbent may make it economically attractive only for plants near geologic deposits of nahcolite or trona. Potential waste disposal restrictions may also limit the technique's appeal among electric utilities. Furthermore, its effectiveness for high-sulfur coal applications has yet to be demonstrated. These and other issues

B&W print returned to R. Hooper 3/9/84

are the subject of research sponsored by EPRI and others.

Incentives to address these problems are substantial. More than 80% of the coal-fired generating capacity controlled by flue gas desulfurization (FGD) systems in the United States presently employs conventional wet lime/limestone scrubbing technology, a very expensive process. In wet scrubbing, flue gas that has been cleaned of fly ash in an electrostatic precipitator or fabric filter baghouse is fed through a large scrubbing vessel, where it is sprayed with an alkaline calcium reagent in a slurry. The reagent absorbs SO_2 to form a sludge, which is then thickened, filtered, and discarded in a landfill or disposal pond.

Wet scrubbing is effective in removing SO_2 from flue gas, but this removal comes at a high cost. The complex hardware of wet scrubbers, combined with reagent and waste disposal requirements, can account for as much as 25% of the capital and operating cost of a new 1000-MW generating plant; the size of the apparatus required can nearly equal that of the generating plant itself. Moreover, utilities have experienced numerous problems in operating the massive scrubbers, many of them related to the use of a liquid slurry medium. Chief among the difficulties are slurry nozzle plugging and equipment corrosion.

Although the utility industry has become more familiar with wet scrubbing systems in recent years and the reliability of such systems has been greatly improved, use of the technology has been more the result of its commercial availability for regulatory compliance than its technical popularity. Some of the drawbacks are avoided with a variation called spray drying, which also uses a wet slurry but produces dry waste; however, spray drying still has some disadvantages. Water requirements, although less than for conventional scrubbing, remain significant. Capital costs for hardware, as well as operating and maintenance costs, make spray drying's economics currently attractive only for coals containing 2% or less sulfur. A preferred desulfurization route would require no slurry, water, or major additional hardware.

Minerals for emissions control

Sulfur removal by dry injection of sodium compounds may be the answer. It requires only equipment already in common use at coal-fired plants, no water is needed, scaling and corrosion are minimal, and flue gas reheating is not necessary. In addition, dry injection results in combined removal of SO_2 and fly ash. Cumulatively, these factors account for a capital cost advantage of \$100–150/kW compared with conventional wet scrubbing for new or retrofit boilers, depending on site-specific factors.

Nature provides a plentiful stock of the minerals needed for dry injection. Nahcolite, which consists almost entirely of sodium bicarbonate ($NaHCO_3$), is found in great abundance in oil shale formations of the Piceance Creek Basin in northwestern Colorado; identified deposits are estimated at over 30 billion (10^9) tons. Trona, containing about equal percentages of sodium bicarbonate and sodium carbonate, or soda ash (Na_2CO_3), is a raw material used for glassmaking; it is already mined in significant quantities from the Green River Basin in southwestern Wyoming. Large deposits are also found in some dry lake beds near the southern Sierra Nevada in California.

In tests to date, dry injection using nahcolite has provided greater overall SO_2 removal than trona, suggesting that sodium bicarbonate is the preferred sorbent compound. In what might seem a contradiction, closer analysis of the chemical steps involved indicates that the SO_2 actually reacts with sodium carbonate in either case. The bicarbonate thermally decomposes to carbonate to react with sulfur in a two-step process.

Bicarbonate particles decompose in "popcorn" fashion in the flue gas duct and on the fabric filter, exposing more reactive particle surface area. Because nahcolite contains a higher percentage of bicarbonate, that sorbent produces more reactive surfaces. Researchers believe this explains why nahcolite is more effective in SO_2 removal than trona.

Nevertheless, the economics of mining nahcolite locked in oil shale formations may impede its commercial availability. Thus, recent attention has focused on trona, which is already an item of commerce.

Two decades of testing

EPRI's investigations of sorbent injection began in 1976 with a study of the technical and economic feasibility of the process; the work soon led to bench-scale laboratory tests and later to full-scale testing. The EPRI research, however, represents only part of a long history of trials carried out by individual utilities and other companies interested in developing the technique's commercial potential.

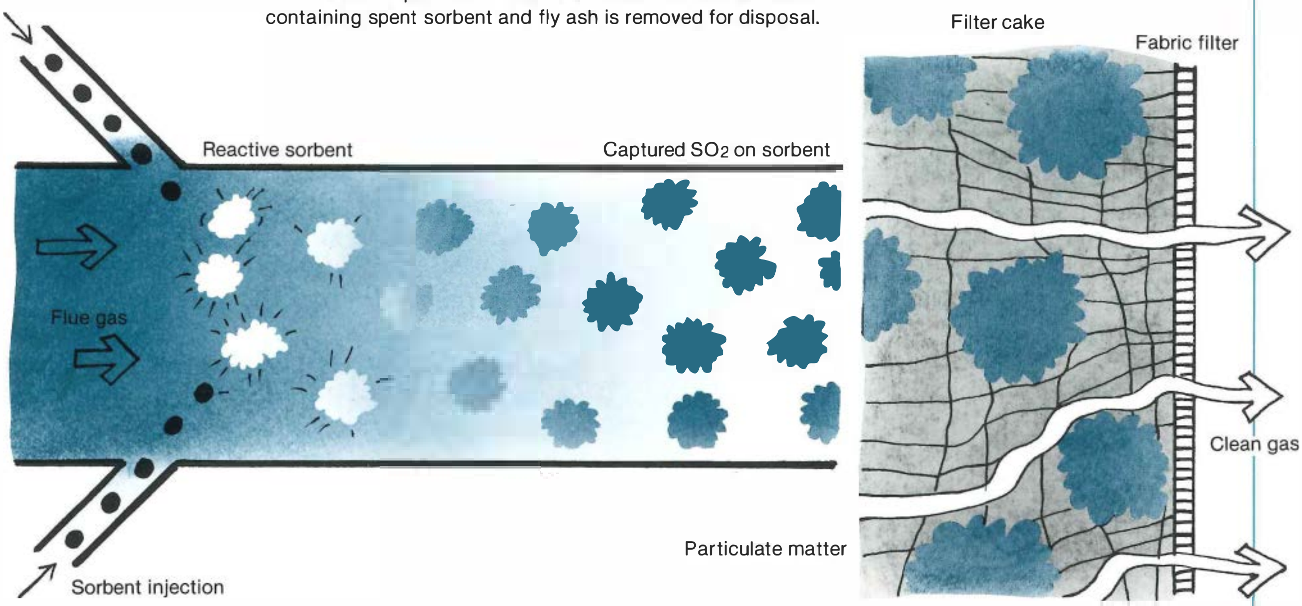
Southern California Edison Co. conducted the first reported tests of nahcolite injection for flue gas desulfurization at its Alamitos station in the mid 1960s. Despite encouraging results, the approach was not pursued further at the time because nahcolite was not commercially available.

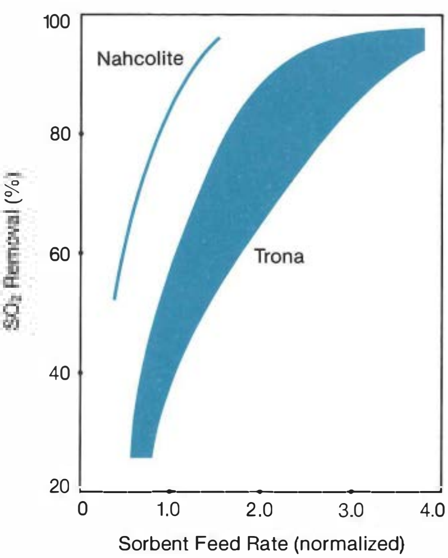
Tests by other companies followed in which various injection methods and process configurations were examined. In 1974 Wheelabrator-Frye, Inc., demonstrated the feasibility of full-scale application of sorbent injection with a fabric filter at Colorado Ute Electric Association's Nucla station. The best SO_2 removal observed was about 70%—an encouraging result—but the nahcolite consumption required to achieve that removal was unacceptably high.

The early tests were made under experimental limitations that hampered efforts to optimize the process. The coarse, unpulverized sorbent that was used resulted in poor utilization of the product. Temperature effects and the importance of injection location were not well understood. In addition, at this early stage of development, capital and operating costs were not defined.

Two factors were instrumental in sus-

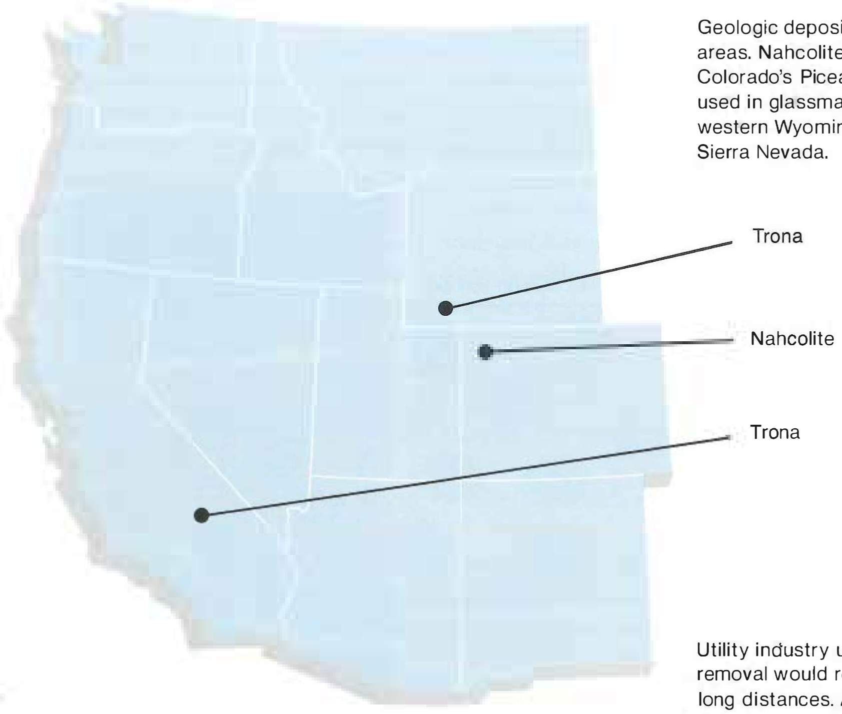
Sorbent particles enter the hot flue gas, where molecules of sodium bicarbonate transform to sodium carbonate in "popcorn" style, exposing more particle surface area. As the sodium carbonate passes through the flue duct, it reacts with SO_2; then it collects with particulate matter on fabric filters. Filter cake containing spent sorbent and fly ash is removed for disposal.





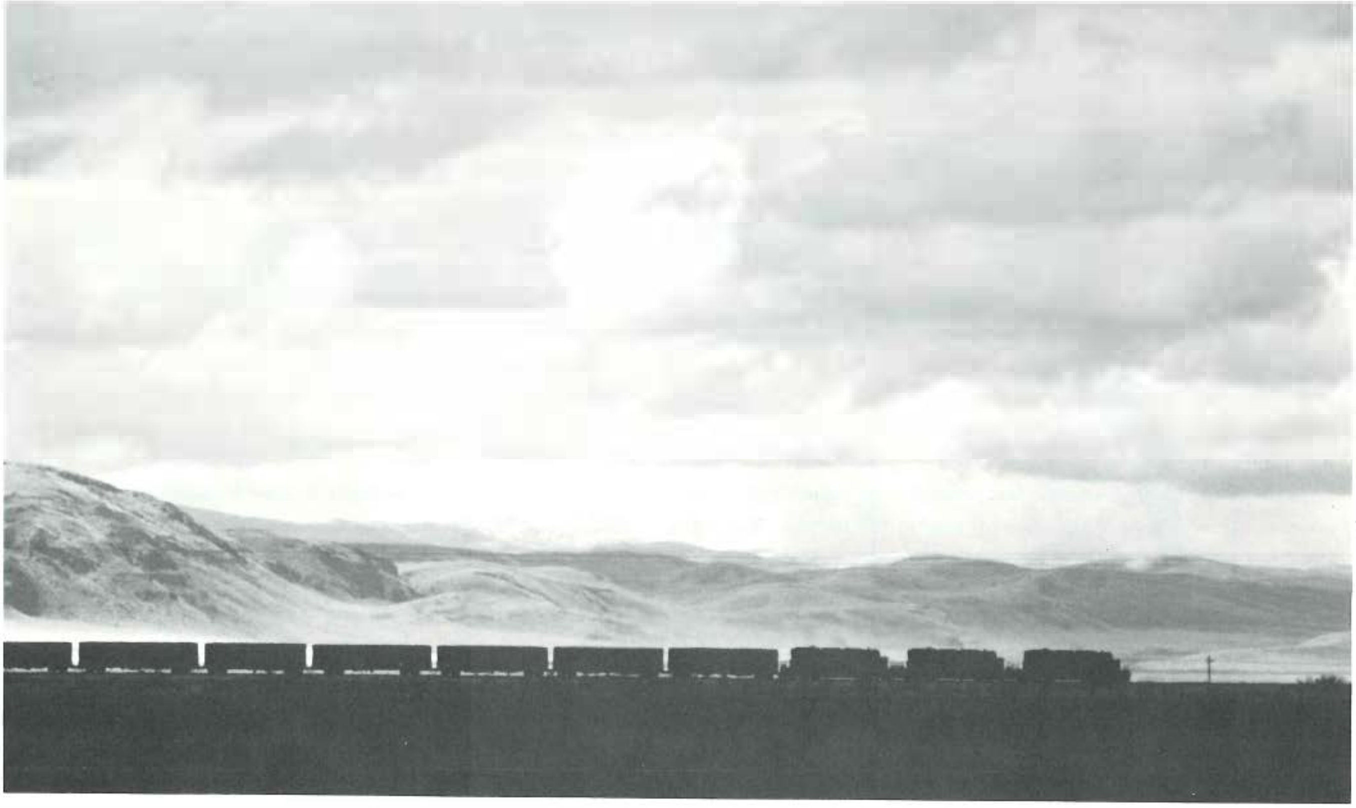
Full-scale dry injection tests found the SO_2 removal efficiency of nahcolite and trona to be a function of the amount and purity of sorbent injected. (The feed rate was normalized to the rate theoretically necessary to capture all sulfur.) The range of results for trona from three sources indicates the importance of sorbent purity. The Environmental Protection Agency's New Source Performance Standards require 70% SO_2 removal from low-sulfur coal.

Reagent Deposits



Geologic deposits of sodium sorbents are confined to three main areas. Nahcolite is found in oil shale formations in northwestern Colorado's Piceance Creek Basin. Trona, the source of soda ash used in glassmaking, is mined from the Green River Basin in southwestern Wyoming and from dry lake beds near California's southern Sierra Nevada.

Utility industry use of nahcolite and trona as reagents for sulfur removal would require large quantities of sorbent to be transported long distances. An EPRI-sponsored economic assessment indicates that unit train shipments could move the needed volume of sorbent at a reasonable cost to coal-fired plants throughout the West and Midwest.



taining utility industry interest in dry injection. The advent of fabric filter baghouses for fly ash control led some utilities to look for ways of combining desulfurization and fly ash removal systems. Dry sorbent injection seemed a good candidate to fill that role. Moreover, regulatory requirements to reduce sulfur as well as particulate emissions grew progressively more stringent.

"By the mid 1970s," notes Carr, "the industry needed a comprehensive research program to integrate the results of earlier work with carefully designed tests that would produce a solid data base on which to make investment decisions." EPRI was the logical parent for such a program.

Beginning in 1980, full-scale dry sorbent injection tests were run on the 22-MW Unit 1 of Public Service Co. of Colorado's Cameo station near Grand Junction, Colorado. Stearns-Roger Engineering Corp. designed the injection system for the Cameo tests, which were sponsored by PSCC, EPRI, and Multi-Mineral Corp. Several western subbituminous low-sulfur coals were fired in the Cameo tests, in the range of 0.5–0.8 wt% sulfur.

The first test phase examined the effects of sorbent feed rate and baghouse operating parameters on sulfur removal using nahcolite; a second, similar phase tested trona and soda ash (a commercial form of sodium carbonate manufactured from trona).

The nahcolite testing demonstrated steady-state SO_2 removals of 75–83%, using a stoichiometric sorbent feed rate—that is, using the amount of sorbent theoretically necessary to react with all the SO_2 in the flue gas stream to form sodium sulfate. Inert impurities in both nahcolite and trona, however, require the use of more sorbent for a given level of SO_2 removal than would be necessary with pure product.

The Cameo tests showed that the reaction between nahcolite and SO_2 decreased nearly 40% when baghouse temperature was reduced from 300°F (148°C) to 275°F (135°C), both of which are in the normal range of flue gas outlet temperatures. This result has important implications for low-load conditions on an operating plant, when the inlet temperature to the baghouse would likely be less than optimal. Engineering solutions are available, however, including nahcolite preheating or sorbent injection into a higher-temperature region of the flue gas stream.

Nahcolite injection had no significant impact on baghouse operation. Researchers observed a 10–20% increase in baghouse pressure drop, but this is still within the normal operating range. However, the tests did highlight the importance of sorbent injection technique and location in achieving a uniform reagent distribution among the baghouse compartments.

In the second test phase, injecting similar (stoichiometric) quantities of three grades of trona resulted in SO_2 removals of around 55%—significantly better than the 40% achieved in earlier bench-scale studies. Further tests revealed that the use of only 30% excess trona yielded SO_2 removals of 70%. In contrast to the results with nahcolite, reducing baghouse temperature to 245°F (118°C)—slightly below normal operating conditions—had no significant effect on trona's reaction with SO_2, which was found to be more rapid than that of nahcolite at the lower temperature.

Soda ash was largely ineffective in removing SO_2 at any injection rate. According to Richard Hooper, an EPRI project manager at the Arapahoe Test Facility who has managed much of the work on dry sorbent injection, researchers believe the thermal decomposition seen with sodium bicarbonate does not occur with the refined soda ash. "Without the popcorn effect that creates more reactive surface on the particles," explains Hooper, "an initial layer of sodium sulfate forms on the particle surface of the reagent and then blocks further reactions, limiting sulfur removal."

The Cameo tests showed SO_2 removal efficiency to be primarily a function of the type and quantity of sorbent injected. Nahcolite was found to be the most effective, achieving 70% SO_2 removal at a stoichiometric ratio of 0.75; for trona, a stoichiometric ratio of 1.3 was required for the same 70% removal, although higher removal efficiencies are possible. (The Environmental Protection Agency's current New Source Performance Standards require 70% SO_2 removal from low-sulfur coal.)

Uncertainties remain

Dry sorbent injection is not a panacea for controlling sulfur emissions. In addition to the limited geographic availability of the sorbents, which may work against their practical application in the eastern part of the country, two significant uncertainties explain why the technique has not been widely used to date: unknowns associated with waste disposal and the lack of commercial availability of large quantities of sorbent for the utility market. EPRI is funding research to learn more about the potential costs and problems of waste disposal. And as more utilities show interest in dry sorbents, reagent suppliers have indicated a willingness to meet a potentially significant utility industry demand.

Compared with a spray dryer, sorbent injection produces 5–7% more waste. The spent sorbent cake removed from baghouse filters following dry injection contains fly ash mixed with sodium compounds, including sodium sulfate and sodium carbonate. And because the sodium products are largely water soluble, disposal presents special problems. Containments must be designed to prevent leachate from reaching surface or ground water. Fortunately, most of the area of prime applicability for dry sorbents has low average rainfall.

Stearns-Roger designed a hypothetical disposal area of six clay-lined cells in an economic analysis performed for EPRI. A layer of rocks provided drainage of the excavated cells, which were sloped to one corner. A clay-lined holding pond was designed to contain any leakage. Stearns-Roger estimated waste disposal costs of

ECONOMICS OF DRY INJECTION

Dry sorbent injection's lower expected capital costs led EPRI to sponsor an economic evaluation of the process. Stearns-Roger Engineering Corp. conducted the study for a hypothetical new power plant in Wisconsin with two 500-MW boilers firing 0.48% sulfur coal. The sorbent injection system was designed for 70% SO_2 removal.

The analysis included design and cost studies of necessary subsystems for reagent pulverizing, handling, and waste disposal. It compared dry sorbent injection with lime spray drying, another possible alternative to wet scrubbing. Reagent costs of $100/t were assumed for nahcolite, $75/t for trona, and $60/t for lime, FOB at the power plant.

The economic viability of dry injection largely depends on the delivered cost of the reagent, the sulfur content of the coal, and the level of desulfurization required, the study found. Capital costs for dry injection equipment, not including the cost of a baghouse, were estimated at about $25/kW, while those for spray drying were around $115/kW.

Major cost components of a dry injection system are the reagent receiving and storage areas, the pulverizing mill, and pneumatic injection equipment. The equivalent cost component for a spray drying system is the absorber—a large vessel in which the reagent reacts with SO_2.

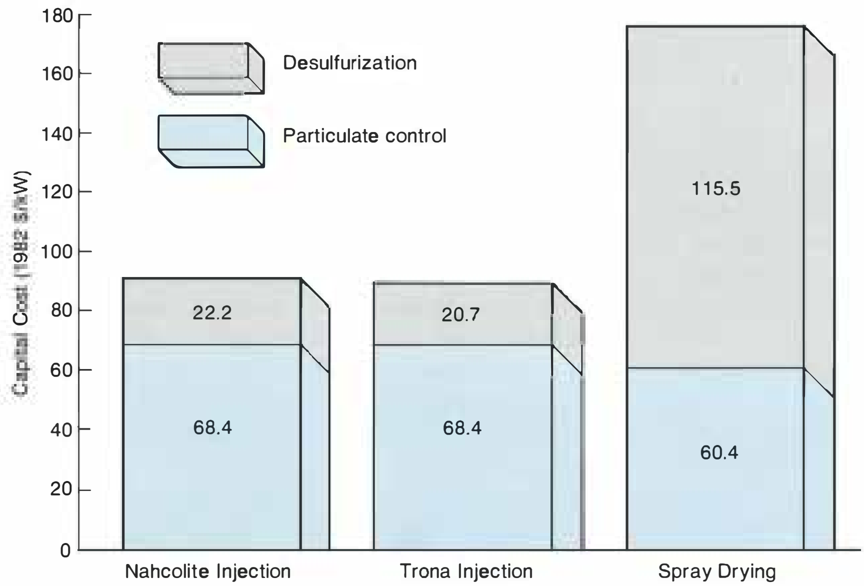
Reagent costs used in the study included transportation. Depending on a plant's location relative to sources of nahcolite or trona, transportation costs could be significant, making dry sorbent injection less attractive for plants in the eastern United States. But the most economic method of moving the reagent—unit train shipment—could bring large quantities of reagent to plants throughout the West and Midwest at a reasonable cost.

For the design study case (two 500-MW units firing 0.48% sulfur coal), a nahcolite injection system would require about 140 cars (14,000 t) per month, while a comparable use of trona would involve about 150 cars (15,000 t) per month.

Levelized costs, calculated as the additional cost to a utility to produce power as a result of adding an FGD system, were estimated at 5–6 mills/kWh for dry injection, compared with 7.5 mills/kWh for spray drying. For dry injection levelized costs are dominated by the cost of reagent, whereas the largest component for spray drying is the hardware capital cost.

Sensitivity analysis of the impact of unit size on levelized cost indicates no significant economy of scale with dry injection. Spray dryers, on the other hand, show good economy of scale because capital is a much larger proportion of levelized cost.

Other important factors in the economic analysis include a maintenance requirement for dry injection that is approximately 10% that of a spray dryer; utility horsepower requirements to operate the equipment are about 70% less than for spray dryers. □



$7.40/t for the soluble fly ash/sorbent injection waste, compared with $4.60/t for relatively insoluble fly ash/spray dryer waste.

One focus of current work in disposal of sorbent waste is the development of a technique to fix the sodium ions in the residue, rendering it insoluble. A simple insolubilization process, if it is proved technically and economically practical, could permit disposal of the fly ash, spent sorbent, and bottom ash together in a conventional landfill.

Before utilities have significant quantities of sodium waste to dispose of, however, they must use significant quantities of sorbent for desulfurization. And before that happens, utilities have to be convinced not only that the technique makes economic sense, but that the reagent market is capable of handling potential utility demand. The trona requirement for two 500-MW plants used in an EPRI base case study is 178,000 t/yr; this represents approximately 6% of the mining capacity of the largest trona mining company.

But as EPRI's Carr points out, suppliers of trona, as well as potential suppliers of nahcolite, are showing increasing interest in the utility market. "There's a lot of activity going on," notes Carr, "and a lot of it stems from the fact that the bench-scale work and the demonstration at Cameo showed that the process works.

"Trona suppliers are very interested in developing the utility market. Demand for glass, the largest present use for trona, is down because of the decline in new construction and the use of cheaper materials. So a lot of trona suppliers are spending a fair amount on their own for research to try to improve the reagents for utility application—to remove the impurities and improve the reactivity and utilization. They're also looking at the waste disposal aspects," Carr adds.

Texasgulf Chemicals Co. and FMC Corp., companies already mining trona for soda ash in Wyoming's Green River Basin, and Cominco American Corp., which operates a trona mine near Owens Lake in California, recently announced commercial availability of the mineral as a utility reagent.

EPRI's research program in dry injection will encompass all of the significant areas of uncertainty in the next few years. In addition, researchers will explore dry injection's potential for use in conjunction with electrostatic precipitators (ESPs)—a development that could greatly broaden its applicability because substantially more ESPs are in use at coal-fired plants than are baghouses.

"If we can find a way to make all of the sorbent reaction occur in the ductwork, whether by preconditioning the reagent or some other means, dry injection could work with ESPs," notes Carr. "This would be a very important development."

Besides nahcolite and trona, other materials may also prove effective for dry scrubbing. Injection of hydrated lime (a calcium compound) has reportedly achieved SO_2 removals of as much as 75% in limited tests on high-sulfur coal. "Hydrated lime looks like a promising option for partial SO_2 control on high-sulfur coal," says Carr, "but much R&D is still needed to understand how it works." The Institute plans further study of hydrated lime beginning this year.

A demonstrated option

Dry sorbent injection has been demonstrated effective for removing SO_2 from boiler flue gas; compared with costly and cumbersome wet scrubbers, the capital cost and mechanical advantages of sodium sorbents are clear. But the utility industry's adoption of the technique will depend on a host of economic variables as well as on political and regulatory developments. If more stringent emissions control requirements are legislated for existing plants, then dry sorbent injection may be a relatively simple and low-cost retrofit option. As a control technology for new plants using low-sulfur coal, its advent is more strongly inhibited by the current lack of construction of new coal-fired generating capacity.

To date, only one utility is known to have firm plans to employ the technique. Public Service Co. of Colorado is designing its next 500-MW coal-fired unit, slated for service by 1990, to use dry injection. Although demand and capacity considerations have delayed construction from the original date, design work continues, according to George Green, PSCC manager for governmental licensing and planning. "Based on our participation in the Cameo tests, our proximity to the sources of sorbent material, and other economic factors, we think it's the best way for us to go on our next unit," says Green.

Other utilities, meantime, have begun testing dry injection, while a growing number are expressing interest in the work already performed under sponsorship of EPRI, PSCC, and others. Dry injection appears to have a definite future in utility emissions control. ■

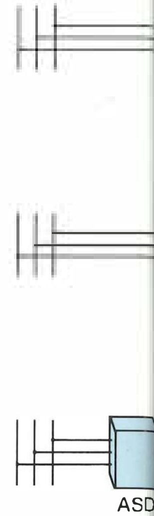
Further reading

Dry SO_2-Particulate Removal for Coal-Fired Boilers, Vols. 1 and 2. Final report for RP1682-2, prepared by KVB, Inc., March 1983. EPRI CS-2894.

Bench-Scale Study of the Dry Removal of SO_2 With Nahcolite and Trona. Final report for RP982-8, prepared by KVB, Inc., March 1981. EPRI CS-1744.

This article was written by Taylor Moore. Technical background information was provided by Robert Carr and Richard Hooper, Coal Combustion Systems Division.

Pacing Plant Motors for Energy Savings



Electronic adjustable-speed drives (ASDs) allow power plant auxiliary motors to work only as hard as they need to. In some cases, ASDs can reduce energy requirements by 30–50%, while minimizing wear and tear.

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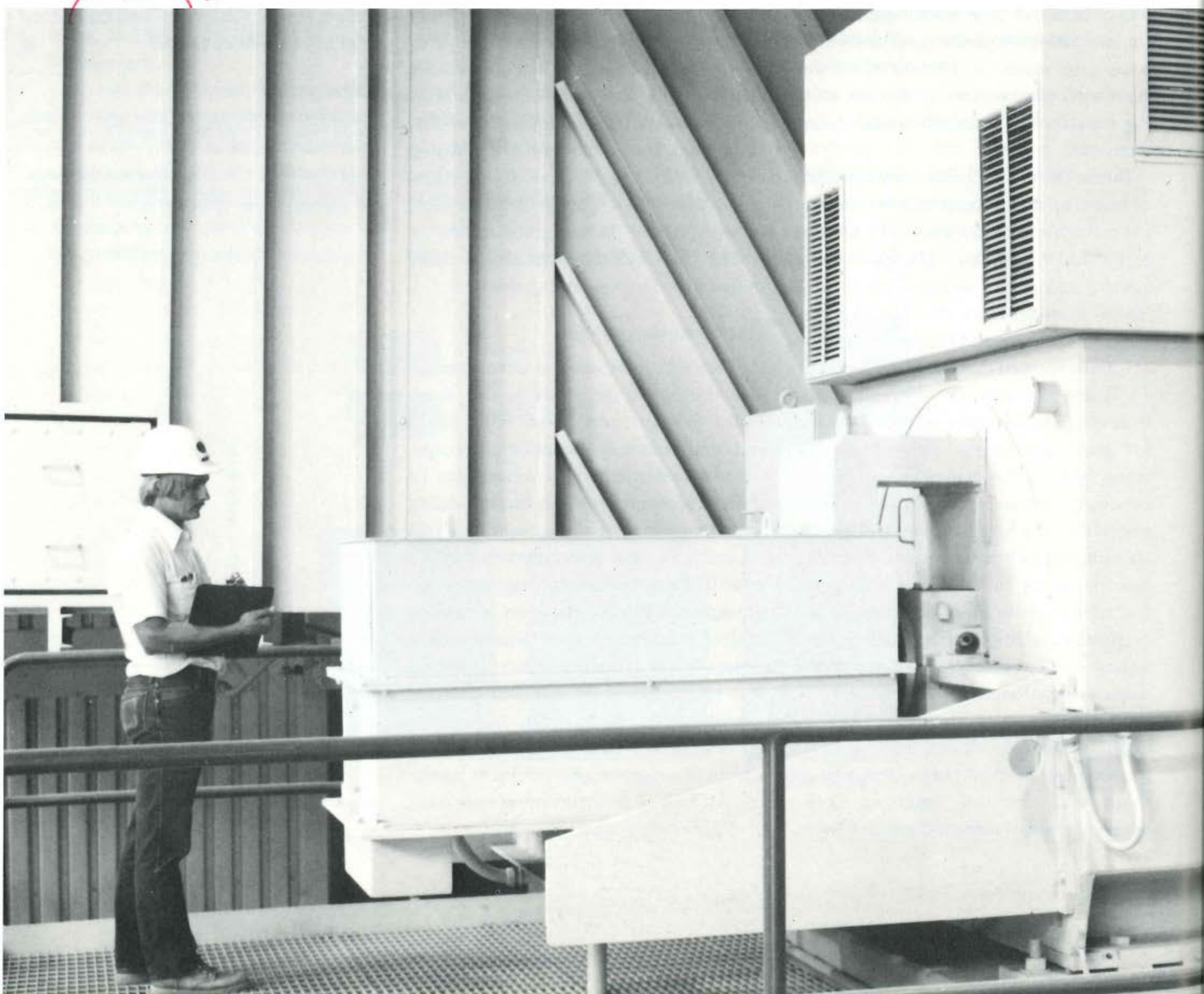
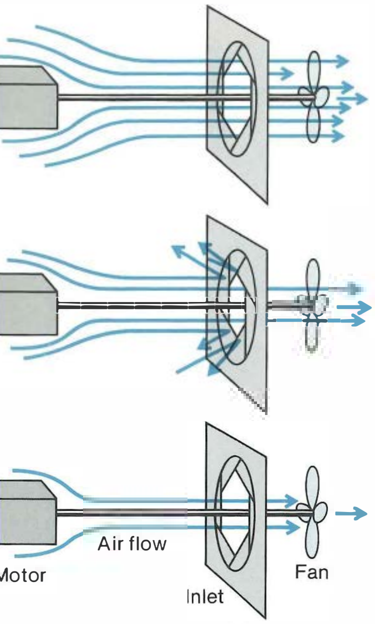




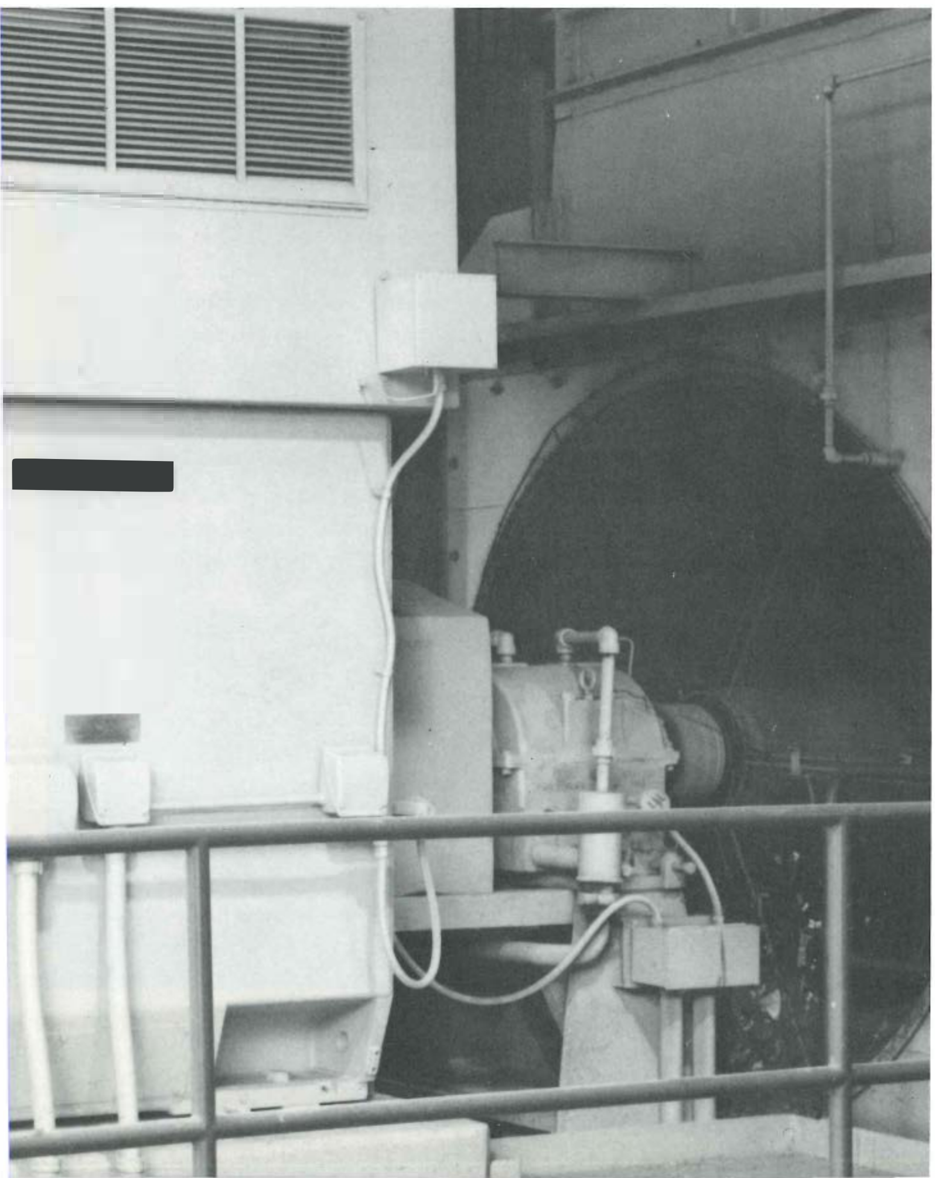
Most of the motors that run power plant fans and pumps operate at a single, constant speed. This is fine when the plant is running full bore: the boilers need maximum combustion air from fans and maximum feedwater from pumps.

When the plant is cycled down to less than rated power, boilers require less combustion air and feedwater. Yet the fans and pumps run by constant-speed motors keep churning at top speed. To reduce the air and water going to the boiler, air flow is throttled by mechanical inlet vanes, and water flow is modulated by control valves. Substantial energy is dissipated by these closed vanes and valves.

Instead of controlling air flow with inlet vanes or water flow with control valves, electronic ASDs can reduce flow by varying the speed of the motor itself—and hence the speed of the fans and pumps—to match plant duty cycles. The result: energy savings.

Every power plant fired by coal, gas, or oil uses a good part of the power it produces just to keep itself going. Electricity from a plant bus runs motors that, in turn, run huge fans; the fans force the air required for combustion through boilers. This simple partnership of induction motor and fan is highly reliable and has been doing utility duty since the industry began.

But this steadfast system can also be a wasteful one. The motors that turn the fans are usually designed to operate at a single, constant speed, so the fans always turn at a constant speed as well. If less than full power is required from a plant, the air flow forced through the boilers by the fans must be throttled by a system of mechanical dampers to match boiler air requirements, while the motor and fan continue to run full bore.



Constant consumption

The energy wasted is substantial. A 500-MW plant operating at full power may require 10 MW to drive its fans; yet even when the plant is cut back to a mere 100 MW, the fan drives still consume nearly 5 MW. And fans aren't the only culprits: giant pumps that supply feedwater to the boiler are often run by constant-speed drives, and they require a similar amount of energy regardless of whether the plant runs at full power or not.

This wasted energy wasn't of particular concern when the drive systems in many power plants were originally installed. At the time, utilities preferred to sacrifice a few megawatts rather than tamper with the trusty constant-speed drive. But with today's emphasis on energy efficiency, many utilities have to ask themselves if they can afford to hang on to these reliable but energy-wasteful constant-speed drives.

A better alternative may be the adjustable-speed drive (ASD), which can increase or decrease motor speed and thus adjust fan or pump output to suit changing power requirements. ASDs can reduce fan and boiler feedpump energy requirements by as much as 30–50%, according to Ralph Ferraro, a power electronics specialist and technical manager for electric interface and control systems in EPRI's Energy Management and Utilization Division. By permitting slower, more gradual startups, ASDs can also reduce wear and tear on motors; and by allowing operation at lower speeds, ASDs can extend fan and pump life. ASDs can also keep startup current surges to a minimum, thereby prolonging the life of transformers and switchgear.

Because of their ability to save energy and to spare wear and tear, ASDs are becoming increasingly popular for general industrial applications (see box). ASDs have not, however, been widely used in power plants. The reason is simple: until about five years ago, the only ASDs available in the 1000–10,000-horsepower sizes required for utility boiler fans and feedpumps have been mechanical drives, such as hydraulic clutches. Because the mechanical ASD must be placed between the motor and the fan or pump and because the drive is so bulky, retrofits have been costly and inconvenient, usually requiring radical repositioning of heavy plant equipment, construction of new motor foundations, installation of new electric couplings, and other major work.

Mechanical ASDs installed in new plants avoided these retrofit problems, but even in new plants these drives have not been especially popular. They may sustain considerable losses from friction, resulting in reduced efficiency; mechanical drives also have high maintenance costs.

Enter electronics

But a new generation of ASDs is following close on the heels of the older mechanicals: solid-state electronic ASDs. This new technology has become increasingly available over the past decade, and its benefits have persuaded many utilities to reconsider ASDs.

Electronic ASDs' advanced hardware and software make them more compact than their bulky mechanical counterparts, so retrofits are a relatively simple undertaking. Electronic ASDs also come out ahead in efficiency. Because these systems have no moving parts, they have no friction, so efficiencies are much higher than those of mechanical ASDs, particularly over a wide range of speeds. Electronic ASDs can also be readily programmed for varied operation, and because they are electronic, they are virtually soundless.

Although utility-sized electronic ASDs have only been commercially available for about five years, some 23 such systems have already been installed in power plants; more are on order. Utilities choose these systems for a variety of reasons and often for a combination of reasons.

Energy savings is one good reason: it was a primary consideration at Houston Lighting & Power Co.'s new two-unit Limestone station, scheduled to start operation by 1985. An economic evaluation showed that electronic ASDs would save some $5.25 million in net energy costs per unit over the plant's life as compared with fixed-speed motors equipped with fluid couplings. (Figures that compare the energy cost savings of electronic ASDs with those of no ASDs at all were unavailable.)

Another good reason to go to electronic ASDs is to extend the life of plant components. When a constant-speed drive starts up, the motor is jerked out of its stationary position and up to full speed by a jolt of electric current. This jolt of current, roughly six times the ordinary operating current, is understandably hard on the motor, the switchgear, and the transformer. Fans or pumps connected to the constant-speed drive may also suffer from being suddenly propelled into motion. And if startups are hard on plants with constant-speed drives, so is operation. The back pressures built up by conventional dampers as they close to regulate the output of a fan or pump are considerable and may quickly wear out component parts.

The amount of plant maintenance, repair, and downtime that could be eliminated by using electronic ASDs has not yet been quantified for the entire industry. Nevertheless, a number of utilities agree that a major reason for installing ASDs is to prevent costly wear and tear.

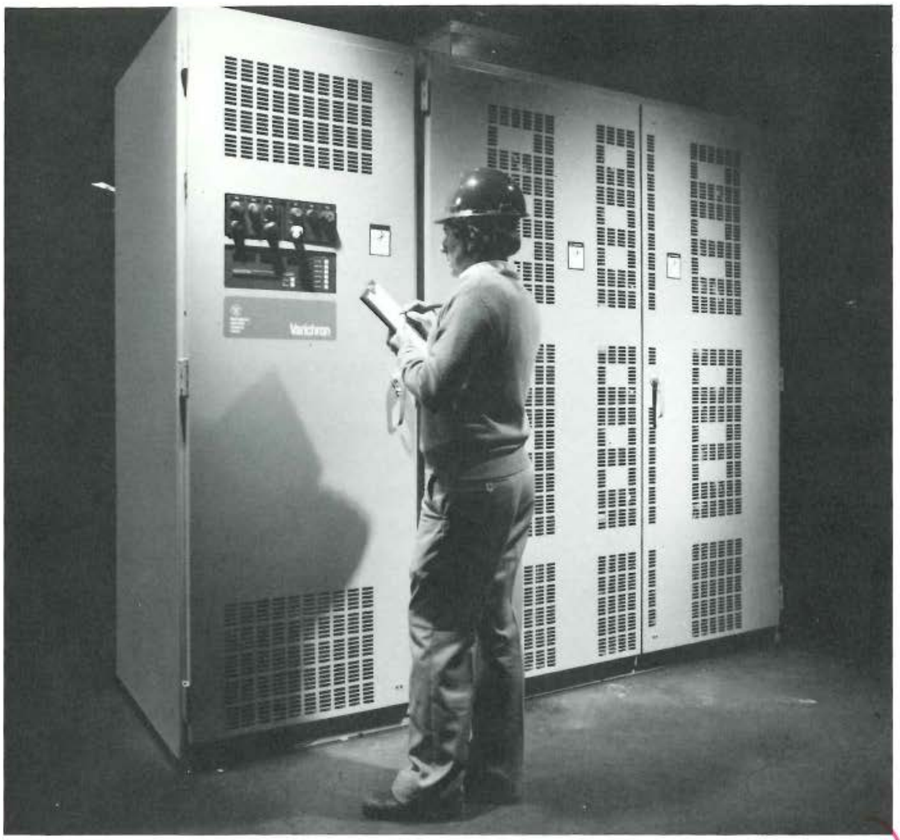
At Ohio Edison Co.'s R. E. Burger plant in Shadyside, Ohio, for example, the installation of larger electrostatic precipitators in Units 4 and 5 demanded larger induced-draft fans and motors. Ohio Edison opted for electronic ASDs to avert voltage drops on existing buses during cold startups and to minimize possible boiler implosions. Sierra Pacific Power Co. recently decided to install electronic ASDs at its Fort Churchill station in Yerington, Nevada, partly to save fuel and partly to reduce maintenance and downtime on boiler feedpump valves.

ASDs may also pay their way through noise control. At Minnesota Power & Light Co.'s Clay Boswell station in Cohasset, Minnesota, electronic ASDs helped reduce the noise level of a new 500-MW unit to a level acceptable to the neighborhood. When the new unit went on-line in 1980, nearby residents complained that the plant had become too loud. The new unit's induced-draft boiler fans were identified as the source of the problem.

Mufflers could have been added to the unit, but they would have significantly increased fan energy consumption. A modeling study showed that slowing the fans would result in substantial decibel reductions, and Minnesota P&L opted for electronic ASDs. The installation of four 8000-hp ASDs cost the utility a steep $8.5 million, but an analysis of fuel savings showed that these costly ASDs would pay for themselves in about six years or less.

Still some questions

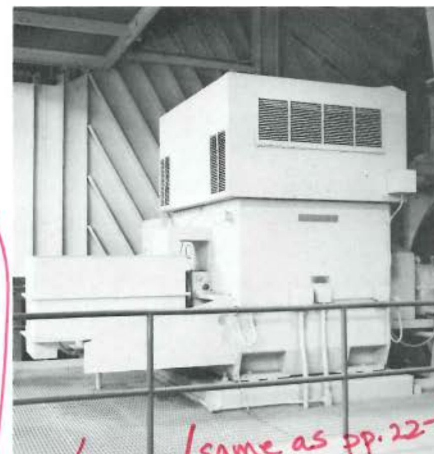
Electronic ASDs are making a good showing at power plants, but there are still questions associated with commercially available equipment that must be resolved before other utilities will be willing to take full advantage of them. Reliability remains the number-one concern. "Utilities have a reliable system out there on the floor right now: constant-speed drive, motor, fan, and control



Where ASDs can make a difference

Any power plant fan or pump whose air or liquid flow varies significantly with cycling duty is a candidate for an electronic ASD. Potential installations include the forced-draft fans that move combustion air through preheaters and the induced-draft fans that help pull combustion air through the furnace and exhaust gases out the stack. Pumps with ASD potential include the feedwater pumps that supply water to the boilers, the condensate pumps that recycle condensed feedwater, and the circulating-water pumps that move cooling water through condenser tubes.

(Photos courtesy Westinghouse Electric Corp.)



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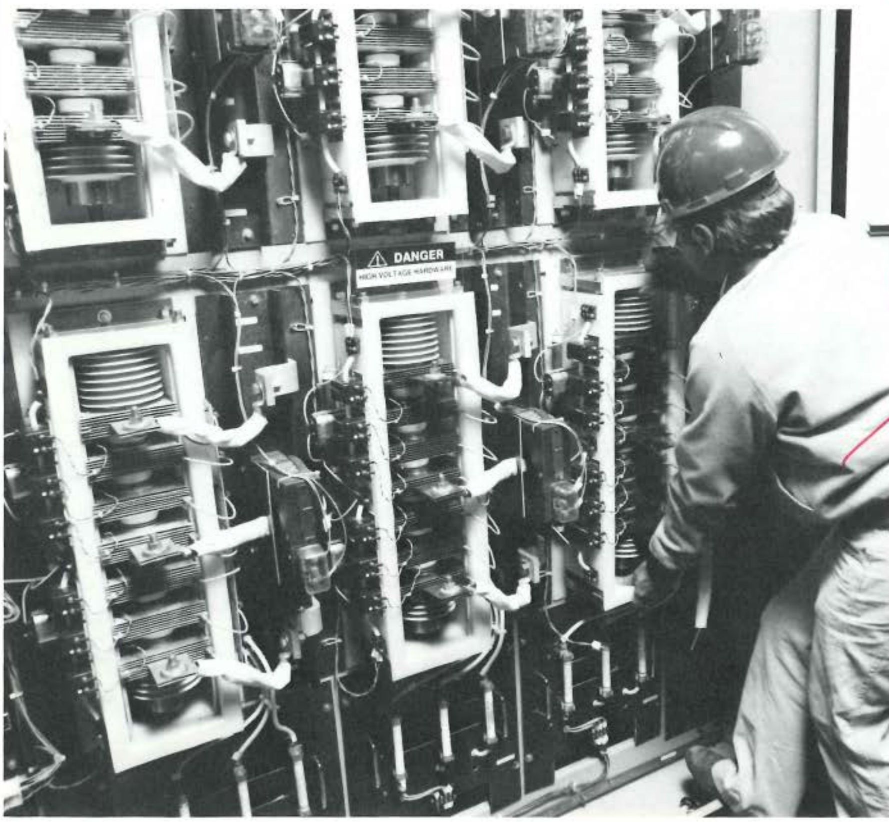


ADJUSTABLE SPEED DRIVES FOR PROCESS INDUSTRIES

Electronic adjustable-speed drives are not just for utility industry power plants. ASDs can also benefit some of the utility industry's biggest customers: the chemicals, oil refining, pulp and paper, and food processing industries. All these industries use multitudes of motor-driven equipment, much of which might be regulated by electronic ASDs for energy savings and other benefits.

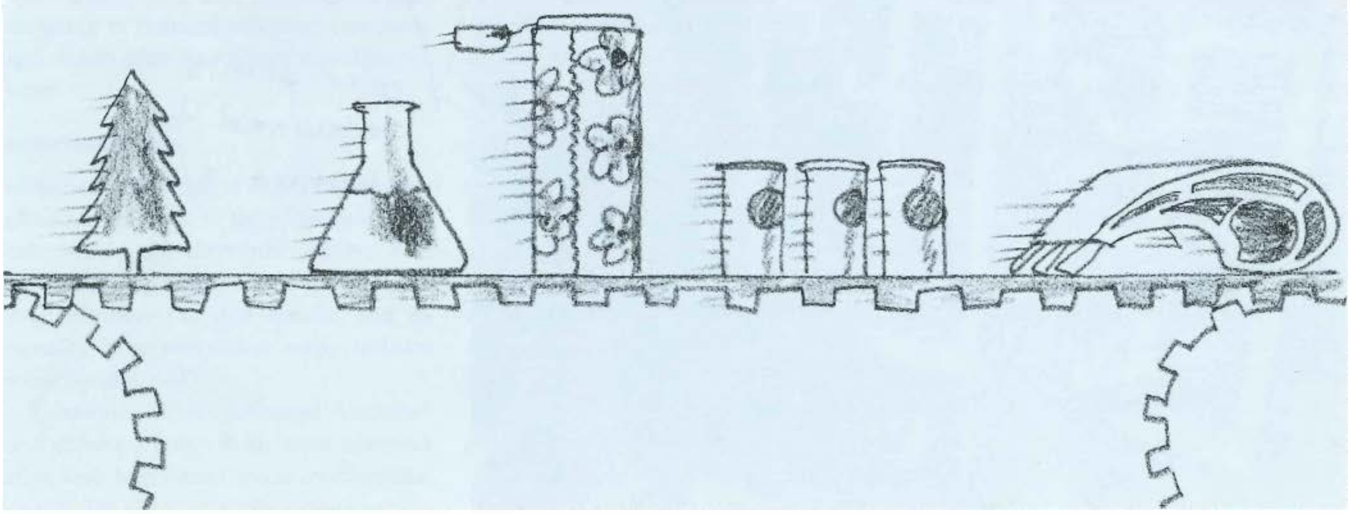
The full extent of the industrial market for electronic ASDs is uncertain, but some recent statistics hint at its potential for energy savings: electric motors consume about 60% of all the electricity used in the United States, and industrial motors account for over 60% of this motor electricity use. Motor-driven pumps, fans, blowers, and compressors consumed over 400 billion kWh in 1980 alone.

A good deal of this motor-driven machinery is already under speed control of one type or another. Adjustable-speed operation is essential to the use of certain industrial equipment, such as textile machinery and conveyors, and before electronics came along, variable speeds were obtained through voltage-controlled electric motors or adjustable couplings that used mechanical, hydraulic, or eddy-current speed regulators. These devices' high cost, limited controllability, and frequent low efficiency generally kept them from being used except where absolutely necessary.

In the early 1970s electronic ASDs with better controllability and efficiency than their mechanical predecessors began to take over textile and conveying jobs. Before long, other industrial users began to recognize the control and fuel savings possible with electronic ASDs, and the new systems were applied to other jobs as well. According to one manufacturer's estimate, over 100,000 electronic ASDs under 50 hp are now in operation, mostly for general-purpose material handling and conveying. There are also several thousand electronic units in the 100–2000-hp range, and a few hundred units of 2000 hp and up.

These installations are only a start. According to one observer, the J. E. Sirrine Co., many prospective industrial users don't fully understand the benefits of electronic ASDs, and some are altogether unaware of the technology. An estimated 13.2 billion kWh are wasted annually through inefficient motor throttling and damping.

To help reclaim some of that wasted energy, EPRI and Sirrine are collaborating on a new project to get sound technical information on electronic ASDs out to industrial customers through their local utilities. Contractor Sirrine will work directly with utility end-use groups to identify industrial customers who might benefit from ASDs and follow up with case studies to confirm those benefits. Data on existing industrial ASD applications will also be collected. The results of the study—a portrait of general industrial ASD use—should encourage other industrial users to take advantage of this new technology. □



dampers," explains Ferraro. "Substitute an ASD for the constant-speed drive and dampers, and you're throwing in a sophisticated piece of equipment that raises reliability questions."

If an ASD breaks down, the utility may have to buy replacement electricity to make up the temporary loss of an entire generating unit. Some utilities ease their concerns about ASD reliability by installing a standby ASD along with the regular drives. Duplication is, however, a costly reliability strategy, and there is no reason why electronic ASD reliability cannot be improved so that utilities will not feel the need for redundancy.

Utilities are also concerned about ASD cost. Right now, the price tag on an electronic ASD is higher than the price tag on a mechanical ASD; with advances in electronic technology, that gap can be expected to narrow before long. According to Ferraro, mechanical ASDs will probably always have a lower capital cost than electronic ASDs, but the electronic system's lower installation and maintenance costs, along with its superior benefits, should make up the difference for many utilities.

Besides the general issues of reliability and cost, electronic ASDs pose some specific technical problems. One involves connecting the ASD to the plant motors. Most large plant motors are simple induction motors; until very recently, electronic ASDs could only be coupled with synchronous motors. When a utility retrofitted an electronic ASD into an existing plant, it was obliged to rip out the plant's old induction motors—many of them reliable workhorses with years of service left—and replace them with more costly synchronous models.

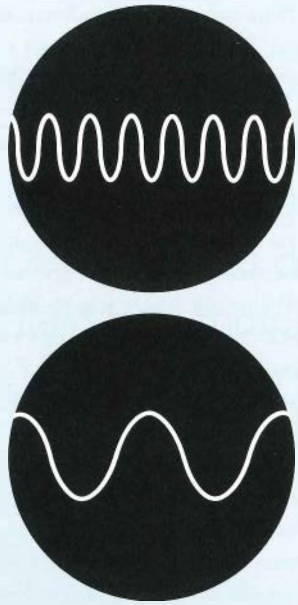
This additional capital cost proved to be an unwelcome expense for many utilities, but thanks to advances in electronics, a number of manufacturers are now offering electronic ASDs that are compatible with the older induction motors. Such ASDs may permit utilities to reduce their capital investment in ASD retrofits. With the original induction motors left intact, utilities can also leave their original damper control systems intact and perhaps muster them as backups if the electronic ASD is out of service.

Another technical concern is harmonics. Any electronic device connected to a power supply—in this case, the ASD attached to the power plant's bus—can produce distorted electronic waveforms called harmonics, which can interfere with the power supply. Typical harmonic effects include heating and eventual failure of the cables, motor, and transformer that are connected to the ASD. Certain harmonics may also produce a drive shaft torque so irregular that the drive could be damaged. Harmonics can also play havoc with other in-house systems, resulting in such local effects as flickering lights, telephone static, and spurious signals to computers. ASD systems can be designed for minimum harmonics, and electronic shields and filters can be attached to existing ASDs to cancel out any objectionable harmonics. But such prevention and solution require advance planning—and usually additional capital.

Making ASDs work

Ferraro is confident that electronic ASDs have a place in the utility industry. But first, ASD benefits must be quantified so

Inside the electronic ASD



The electronic ASD changes motor speed by changing the electrical frequency of the motor's supply voltage. For example, to halve the speed of a motor rated 60 Hz, the ASD reduces the frequency to 30 Hz. ASDs change the frequency by switching thyristors on and off at a different rate.

The ASD must also closely control the quality of the electricity it is sending to the motor. This electricity must contain a minimum of distortion, or harmonics, which can cause heating and eventual failure of the cables, motor, and transformer, as well as harmful torsional vibrations in the drive shaft. ASDs contour the current with thyristors to approximate a sinusoidal waveform.

that prospective users can see what they stand to gain, and any remaining technical difficulties must be resolved to ensure that utilities and their industrial customers enjoy these benefits. These two goals are at the heart of a series of EMU Division projects.

In early 1982 EPRI, United Technologies Corp., and Bechtel Power Corp. studied what would happen if the 6250-hp fans on two 750-MW units at Southern California Edison Co.'s Ormond Beach plant were to be retrofitted with prototype electronic ASDs. Instead of commercially available electronic ASDs, EPRI chose advanced models developed for use with new dc power technologies such as fuel cells and batteries. The objective of the study was not to see if commercial ASDs would benefit conventional plants but, rather, if advanced ASDs being developed for new power technologies could be applied to present-day plants and, in effect, pay for ongoing research.

EPRI compared the capital and operating costs of the ASDs with those of the constant-speed drives actually used in the units. Study results showed that if the units were retrofitted with advanced electronic ASDs, over $1 million a year in fuel costs could be saved for each unit, totaling some $15 million in savings over the remaining life of each unit.

Intrigued by these results, EPRI decided to evaluate the benefits of the more down-to-earth ASD technologies commercially available from manufacturers. EPRI commissioned Bechtel to study the benefits of retrofitting 45 existing power plant units with off-the-shelf ASDs rated 1250, 4000, and 9000 hp. The basis for evaluation would be the economic comparison developed for the previous study.

The retrofits included not only electronic ASDs but also mechanical ASDs such as hydraulic clutches, whichever seemed best for each situation. Bechtel developed equipment specifications and both domestic and foreign manufacturers reviewed them. (Foreign manufacturers were specifically included in the project so U.S. utilities could see what engineers overseas had to offer.) When the results of the retrofit studies were recently tallied, Bechtel found a range of situations in which ASDs would pay their owners back handsomely and a number of situations in which they would not.

According to Bechtel's calculations, one of the leading utilities in the Northeast would save $15.9 million in fuel over the remaining life of one oil-fired 450-MW unit if ASDs were installed on each 4500-hp induced-draft fan motor, 2500-hp forced-draft fan motor, and 2000-hp gas recirculation fan motor. Payback periods for these installations would be 4.6, 6.4, and 4.6 years, respectively. Boiler fans and boiler feedpumps at other plants showed similarly promising savings. Not every retrofit in the study showed savings, of course. Usually, the units that did the most cycling duty and hence had greater need of adjustable speeds were the best economic choices for ASD installation.

Encouraged by the results of this study, EPRI is now stimulating commercial interest in retrofit demonstrations of the most promising available electronic ASDs, backed up with the necessary technical expertise to ensure their success. Utilities owning power plants that look like good candidates for ASDs will be encouraged to install them, with the promise of intensive cooperation between utility, ASD manufacturer, architect-engineer, and EPRI to make the installation a success. Close tabs will be kept on ASD performance and cost, and results made available to all interested parties.

Through this joint effort, participating utilities will get the best possible ASD for their respective plants, and the rest of the industry will get instructive feedback. "It shouldn't be just one utility struggling with one drive manufacturer to solve all the problems of the world," says Ferraro.

Because the utility industry is such a potentially large ASD market, Ferraro anticipates that architect-engineers and ASD manufacturers will be eager to participate in these demonstrations on a cost-sharing basis, which, in turn, should kindle utility participation; EPRI will provide coordination and consultation as necessary. Studies into specific ASD reliability and cost issues will be added to EPRI's program as the Institute gets a better picture of what the research needs are.

ASDs up ahead

Electronic ASDs have a promising future ahead of them—and not only in conventional power plants, new dc power plants, and general industry. As Fritz Kalhammer, vice president, EMU Division, sees it, power and control electronics prices will keep falling, and electronic ASDs will become economically attractive in smaller sizes, reaching applications and customers who would not have considered them previously because of high cost.

For example, ASDs may eventually be used to regulate the speeds of the sizable fans used in the air conditioning systems of large buildings. Someday, ASDs may even reach the residential sector in appreciable numbers, perhaps for regulating heat pump operation. Wherever there is fluctuating electrical demand, there is a possible market for ASDs. The years ahead will see how far reliability can be improved, how low prices can get—and how far ASDs will go in saving money for utilities and their customers.

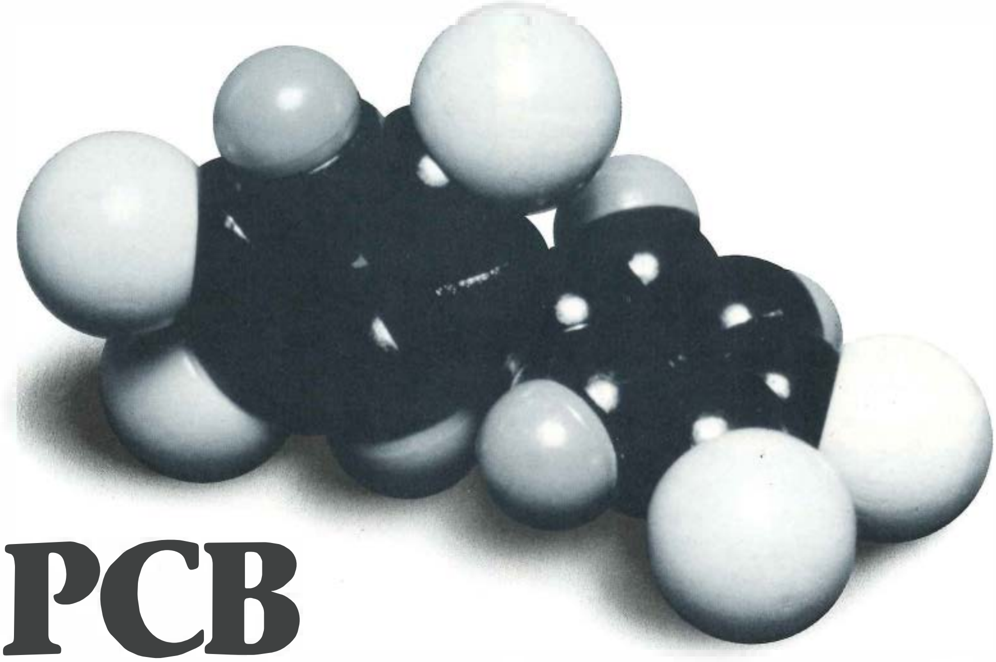
Further reading

Impact of Advanced Power Semiconductor Systems on Utilities and Industry. Final report for RP1201-12, prepared by SRI International, November 1981. EPRI EM-2112.

Techniques for Energy Conservation in AC Motor-Driven Systems. Final report for RP1201-13. prepared by the University of Minnesota, September 1981. EPRI EM-2037.

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

Testing for PCB contamination in the nation's 35 million transformers is an expensive and time-consuming prospect for utilities. Four new devices developed specifically for field use should speed the process and lower the cost.



PCB Detection in the Field

For nearly 50 years, the family of organic compounds known as polychlorinated biphenyls (PCBs) proved extraordinarily valuable to at least half a dozen industries. These versatile chemicals could act as plasticizers in paints or as dye carriers in carbonless copying paper, and they provided useful properties to such diverse products as newsprint, caulking compounds, and insecticides. But their most enduring use came as a fire-retardant insulating liquid in sealed electrical equipment.

Now, it is this very usefulness and enduring quality that has come back to haunt electric utilities. In 1976 the Toxic Substances Control Act called for elimination of PCBs, citing them as a possible hazard to human health. For most industries, that simply meant finding an appropriate substitute, since the products they made with PCBs had primarily transient uses and had already entered the environment. For some PCB-containing devices, such as ballast capacitors in fluorescent lights, no regulations have been issued, and these will also eventually find their way into the environment. But under stiff regulations, utilities not only had to retrieve and destroy most of the remaining 200 million pounds of PCBs in utility equipment, they also had to detect PCB contamination in equipment where PCBs were never intentionally used.

By far the largest quantity of PCBs still in use remains sealed in the transformers and capacitors that utilities used to reduce fire hazards in public places. Their locations are known, and the process of replacing them has been going on for some time. What most utilities do not know, without measuring, is which of 35 million other transformers may have been contaminated with PCBs while undergoing routine maintenance. Because PCBs had been used for so long a time for such a variety of purposes, there seemed to be little need for having separate pumping equipment for servicing different kinds of transformers. Thus, many transformers that use mineral oil as an insulating liquid also contain some trace amounts of PCBs.

Any transformer containing 50–500 parts per million (ppm) of PCBs is, by Environmental Protection Agency regulation, "contaminated." Maintenance on these transformers must now be performed using separate handling facilities, and restrictions also apply to their disposal. Transformers with more than 500 ppm must be treated as if they were actually filled with PCBs and can be serviced only up to July 1, 1984. In order to determine PCB concentrations, all oil transformers will probably have to be tested eventually. For purposes of maintenance and disposal, a utility must assume any particular mineral oil transformer is contaminated until such tests are made. If a spill occurs, the utility must measure soil contamination to determine whether PCB cleanup procedures are necessary.

The need for better tests

Because PCBs constitute a large family of related chemicals, testing for the presence of the whole group is generally complex, time-consuming, and expensive. A biphenyl molecule consists of two rings of carbon atoms linked together; chlorine atoms can attach themselves to any of these carbon atoms except those that join the rings. Altogether there are 209 combinations, of which roughly 100 are commonly found in electrical equipment.

Until now, the standard method for measuring the total amount of PCBs in an oil sample has been gas chromatography, which generally requires an elaborate laboratory apparatus and a specially trained chemist to interpret the results. The technique's principle is simple enough: a sample to be tested is vaporized and carried by a gas stream through a narrow tube filled with absorbent material. This material retains some components of the sample longer than others, so that they arrive at different times at the far end of the tube. There the amount of each component is measured and plotted on a time graph. An analysis may take 45 minutes.

The main problems with this procedure arise in preparing the sample and interpreting the graph. First, a sample of transformer oil must be cleaned with acid to remove extraneous material; then the PCBs are extracted using a solvent. This preparation must be done carefully to produce consistent results. The apparatus itself must also be properly calibrated, using standard samples with known constituents. Finally, the human analyst must be able to distinguish the characteristic pattern of PCB peaks from the other data recorded on the graph.

Done well, gas chromatography can be an extremely powerful tool for analyzing complex organic substances, but it has inherent limitations. Uncertainties of even a few parts per million become critical when the analysis is being used to determine whether or not a federal regulation applies. Generally, researchers expect an error of less than 10%, but when different laboratories are testing, results can deviate much more seriously. For example, when one utility sent the same sample of PCB-contaminated oil to two laboratories, one reported a concentration of 500 ppm, and the other reported only 200 ppm. In spite of these problems, the technique remains the standard method for PCB analysis.

EPRI's role

In response to utility requests for better ways to check for PCB contamination, EPRI has sponsored development of four new tests, designed to complement each other in various applications. For fast, inexpensive screening of transformers, particularly in the field, utilities can use a small chemical test kit or a portable instrument based on X-ray fluorescence. Both of these methods determine the chlorine level in a sample of oil rather than measuring PCB concentration directly; a chlorine reading of less than 20 ppm means that the sample must contain less than 50 ppm of PCBs. Such a screening procedure can save considerable time and money by eliminating the need for more expensive, detailed analysis of a large majority of transformers that are clearly not contaminated.

When direct PCB measurement is required, a new, automated infrared spectrometer can do the job in a fraction of the time now needed for laboratory analysis. Both the sample preparation and analysis of results are computerized for greater accuracy, and the instrument can be operated by field personnel without the need for extensive training.

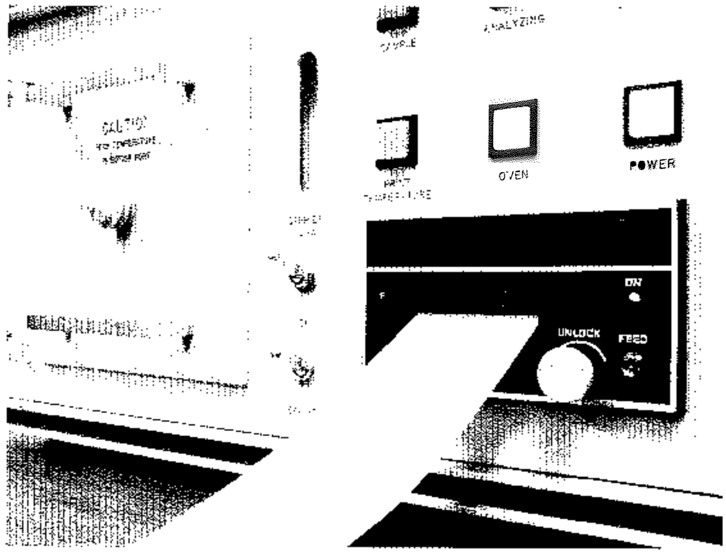
An improved gas chromatograph has also been developed for use in the field, especially for measuring PCB contamination in the environment near a leaking or failed transformer. This device is also highly automated and can be used to test samples prepared directly from soil affected by a spill.

"Before now, utilities had nothing available for measuring PCBs in the field, so the new devices will save them both time and laboratory costs," says Vasu Tahiliani, project manager for EPRI's Electrical Systems Division. "The potential saving to the industry from these four developments is perhaps $750 million, quite a good return on the $1 million invested in the projects over the last three years."

Purple means good news

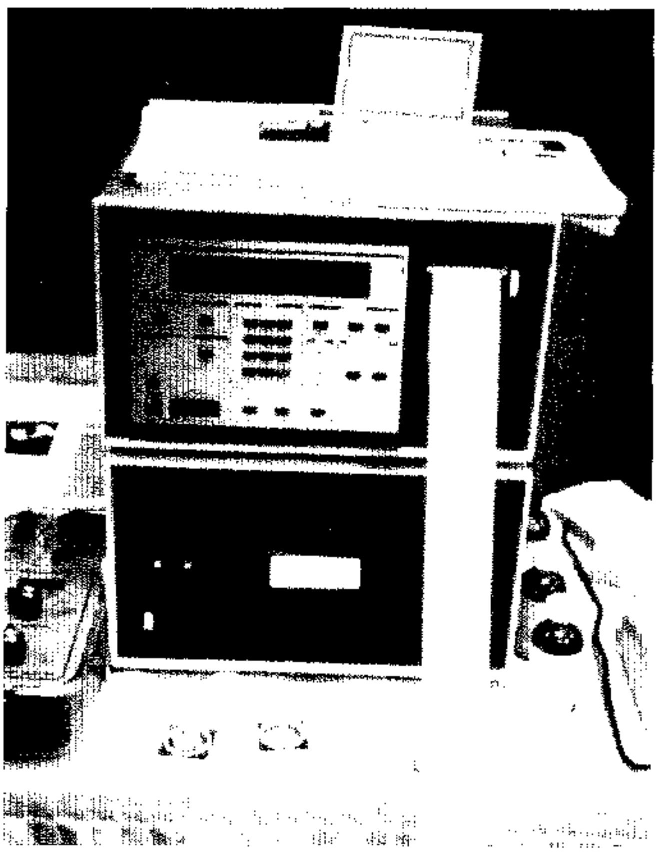
By far the handiest of the new tests, and the one requiring the least initial investment, is the chemical kit used for screening. Called the Clor-N-Oil (an EPRI trademark) PCB Screening Kit, this test device uses premeasured reagents sealed in small glass ampules inside two polyethylene tubes. It is designed to show whether a sample of transformer oil contains less

S-Cubed PCBA-102 gas chromatograph



Clor-N-Oil kit

Four alternatives to laboratory analysis of transformer oil for PCB contamination have emerged from EPRI research. Designed to screen out clearly uncontaminated transformers, the pocket-size Clor-N-Oil kit and the Horiba MESA-200 analyzer both work by measuring the chlorine level in the oil rather than quantifying the PCB concentration directly. For definitive measurements of PCBs, a Battelle FTIR spectrometer or the S-Cubed PCBA-102 gas chromatograph can also be used in the field.



Horiba MESA-200 analyzer

Battelle FTIR spectrometer

than 20 ppm of chlorine, thus demonstrating that it is not legally contaminated. The Clor-N-Oil kit was developed by the General Electric Co. with EPRI funding.

The test procedure for the kit is extremely simple. A small, disposable pipette is used to draw a 5-ml oil sample and introduce it into the first plastic tube. Two glass ampules filled with reagents are then broken in a prescribed sequence by squeezing the soft tube. This procedure strips chlorine atoms from PCB molecules and binds them into a salt. The salt is then transferred, in solution, into the second tube, where two more ampules are broken in sequence. This step chemically combines the chlorine atoms with a precisely measured amount of mercuric nitrate. If some mercuric nitrate is left over, the solution appears purple, meaning that the original sample contained less than 20 ppm chlorine and that no further tests are needed. However, if there is an excess of chlorine, the solution looks clear or slightly yellow. In that case, the utility must conduct a specific test for PCB content.

For most utilities, such screening will eliminate the need for further testing in 50–70% of all transformers. There are two reasons why a positive Clor-N-Oil test result cannot be interpreted as a sure sign of PCB contamination. First, the chlorination level varies among different PCBs by as much as a factor of three. Second, some of the chlorine present may have been introduced by trichlorobenzene, used to thin the PCBs, or by one of the solvents used to clean transformers. This disadvantage is overcome by the relatively low cost of the screening procedure and the speed with which it can be done in the field. The kit costs about $4.00 and is small enough to be carried easily in a jacket pocket.

More than 100 utilities are now testing the Clor-N-Oil kits as part of an EPRI-sponsored trial, and reactions so far have been generally positive. "We intend to use them," says Albert Kirksey, a staff supervisor at Virginia Electric and Power Co. "We'll have them in our field operations so that when a spill occurs we can respond immediately with a screening test." Only about 10% of the company's transformers are contaminated, Kirksey says, so the kit will substantially reduce the cost of testing oil when leaks occur.

For problems at remote sites, the time lost in bringing an oil sample to the laboratory for testing often turns out to be more costly than the test itself, according to Kirksey, since any spill must be considered contaminated until proven otherwise and cleanup must begin immediately. "That gets expensive!" he says, adding that if the Clor-N-Oil test can show immediately that a transformer is not contaminated, the cleanup procedure can be greatly simplified.

Screening in volume

When a utility has to screen large numbers of transformers as part of its program to locate all contaminated units, a new X-ray fluorescence analyzer can provide a cost-effective alternative. Called a Model MESA-200 Total Sulfur and Chlorine Analyzer, the device was developed and marketed by Horiba Instruments, Inc., on the basis of EPRI-funded research and testing by General Electric Co. The price of the unit is about $25,000, and the tests themselves are very inexpensive, costing only $2–$3 each.

Again, screening is accomplished by measuring the concentration of chlorine atoms in samples of transformer oil. The analyzer is compact enough to be used in the field and can be mounted, for example, in the back end of a station wagon. Tests take 2–5 minutes to run, depending on the accuracy required.

Oil samples are prepared in patented disposable cells designed for easy use. When a sample cup is inserted into the analyzer using a slide-out loader, it is bombarded by low-energy X rays from an electron tube designed to minimize background radiation. Since the procedure uses no radioactive source material, it requires no nuclear certification or technician licensing. Atoms in the sample absorb the incident X rays and "fluoresce"—that is, they emit other X rays in characteristic patterns of specific frequencies. A microprocessor analyzes the detected patterns to determine the concentration of chlorine and sulfur atoms. Both of these elements must be measured to get an accurate reading for chlorine, since their characteristic spectra are similar enough to cause confusion.

The Horiba analyzer has been on the market for about two years, and EPRI has sponsored extensive field trials in cooperation with the Salt River Project. These trials consisted of roughly 6800 individual field tests, on site at nine utilities. The instrument proved to be very accurate, with chlorine concentrations measured to within 2–3 ppm.

Although the analyzer requires a significant initial investment, it may pay for itself after only 2000 tests, according to Al Marquez, a consulting test engineer at Salt River Project. This is a relatively small figure, he says, compared with the large number of tests some utilities have to conduct. Duquesne Light Co., for example, has tested as many as 1000 oil samples in a month using the Horiba analyzer. Another advantage, says Marquez, is that the instrument is easy to use and does not require a great deal of operator training.

Faster definitive results

When screening methods have been used to identify possibly contaminated transformers or when specific PCB measurements are needed for some other reason, a new Fourier transform infrared (FTIR) spectrometer can greatly hasten the testing procedure. Battelle, Columbus Laboratories developed this test method with EPRI funding. It uses a commercially available spectrometer, and will soon be available for trial use by utilities. Once set up, the instrument can perform quantitative PCB analysis on 12 samples of oil per hour, either in a laboratory or in the field. During the second quarter of 1984, EPRI plans to equip a station wagon with an FTIR spectrometer so that member utilities can use it to conduct field trials.

FTIR spectrometry is a well-established technology and works on the principle that various compounds will absorb characteristic patterns of infrared radiation. The instrument modulates various wavelengths of radiation at different frequencies. This modulated radiation is focused on the sample, and a detector records the total energy passing through the sample. A microprocessor records and analyzes the energy absorbed at each wavelength. PCBs exhibit strong absorption peaks, the heights of which are proportional to the amount of contamination in a sample. However, the problem with using such instruments to test transformer oils for PCBs has been the presence of too many spectra from other substances.

To reduce this interference, Battelle researchers first considered adding a more sophisticated form of computerized analysis, called spectral subtraction. This method measures the spectrum of uncontaminated oil and subtracts it from the spectrum of a given sample. Unfortunately, variations among different transformer oils turned out to be too great, and the idea had to be dropped. Instead, a chemical cleanup step was added to the sample preparation to remove substances whose spectra could interfere with the PCB analysis.

Again, the first method devised turned out to be not quite satisfactory: PCBs were detected, but the sample preparation was difficult. Finally, the researchers modified a process developed by Union Carbide Corp. to recover oil by removing PCB contamination. A chemical was first mixed with contaminated oil to strip the PCBs and produce a concentrated sample suitable for testing in an FTIR spectrometer. The entire sample preparation process was then automated, using microprocessor control.

At $40,000, the finished instrument is more expensive than the Horiba screening analyzer, but it can produce definitive results on PCB content for about $5 per test. But what is even more significant is that the entire FTIR test, including sample preparation and data output, takes only about 5 minutes per sample. All analysis is carried out by an internal computer, and the operator receives a printed record of PCB content for each sample. Over the range of 50–500 ppm, the FTIR spectrometer measures the concentration of PCBs to an accuracy of within about 10%. After field tests have been completed, EPRI will offer to license commercial rights to this detector.

Toward on-site spill analysis

Perhaps the most difficult test that has finally yielded to automated analysis determines PCB content in soil samples at the site of a transformer leak, approximately 20,000 of which occur each year. A new PCBA-102 gas chromatograph, developed by the S-Cubed Co. under EPRI funding, not only can be used to provide a definitive PCB measurement in oil, but is also the first transportable instrument designed to measure contamination in the spill area itself.

"Our objective is to give utilities a tool they can use to complete a cleanup operation in one visit," says Ralph Komai, project manager in EPRI's Coal Combustion Systems Division, which sponsored the work. "At present, it sometimes takes repeat visits and up to a week for a cleanup crew to reduce PCB soil contamination to required levels," he says. "That's frustrating to a utility and disturbing to the neighbors. This instrument will allow the cleanup crew to tell how well they're doing right at the site."

Two primary problems had to be overcome to conduct gas chromatography in the field: sample preparation had to be standardized and simplified, and a suitable pattern-recognition algorithm had to be developed for automated analysis. The S-Cubed device uses a kit the size of a briefcase to weigh soil samples and extract the PCBs quickly with an organic solvent. The analysis procedure measures standard samples of the four major PCB mixtures and compares their chromatographic patterns with that produced by the soil sample, using a built-in microprocessor.

Each test takes around 10 minutes to perform and costs about $5. The PCBA-102 will soon be available for purchase at about $18,000. Member utilities will soon conduct field trials with an instrument loaned by EPRI for testing contaminated soil samples. Results will then be compared with laboratory analyses of the same samples. Already, 14 utilities have expressed interest in participating in the test program.

Savings for the industry

The task of meeting federal regulations for detection and disposal of remaining PCBs will almost certainly cost electric utilities several billion dollars over the coming years. Part of this task—particularly the special handling required for equipment filled with PCBs—is unavoidable. However, simpler methods for detecting PCB contamination in oil-filled transformers could lead to considerable savings. Locating contaminated transformers is costing some utilities as much as $10,000 a month. New, inexpensive screening and measurement technologies will not only lower such testing costs but also reduce the need for special handling by identifying uncontaminated units more quickly.

"The PCBs present in contaminated transformers represent only a small fraction of 1% of the total PCBs remaining in electrical equipment," says Narain Hingorani, chairman of EPRI's interdivisional working group on PCBs. "That compares to roughly 19% of the material that has already entered the environment. These transformers account for a disproportionate amount of the industry's liability in removing remaining PCBs from service. Our aim has been to reduce that cost as much as possible through better PCB measurement, using sophisticated technology designed specifically for the task." ■

This article was written by John Douglas, science writer. Technical background information was provided by Vasu Tahiliani, Electrical Systems Division, and Ralph Komai, Coal Combustion Systems Division.

Federal Study Evaluates New Hydro Potential

A comprehensive study by the U.S. Army Corps of Engineers has identified candidate sites for hydroelectric power development to the year 2000.

Federal attention to the development of alternative energy sources was renewed when fossil fuel shortages and rapid energy price increases threatened the United States in the early 1970s. To spur an assessment of the nation's hydroelectric power potential and to develop a plan under which this potential could be realized, Congress enacted the Water Resources Development Act of 1976, which called for the National Hydroelectric Power Resources Study (NHS).

The responsibility for this major undertaking was assigned to the U.S. Army Corps of Engineers, a federal water resource agency. The Corps has participated in hydroelectric operation since the 1930s as part of its responsibility for the multipurpose development of the nation's water resources. As a result of its extensive involvement, the Corps is now the largest single U.S. hydroelectric power producer, operating 68 projects with a total capacity of 19,364 MW—about 26% of the country's total installed hydroelectric capacity.

The Institute for Water Resources (IWR), an arm of the Corps that conducts water resource planning and analysis, managed the five-year study, which was completed in May 1983. The 23-volume NHS report includes a 32-page executive summary of the major findings. Organized according to North American Electric Reliability Council regions, the study identifies about 2000 sites that have potential for future hydroelectric development.

The Screening Process

IWR began by making a preliminary list of possible sites, gathering information from numerous sources on all known U.S. dams and dam sites. The initial inventory covered 60,000 potential federal and nonfederal sites. Of these, 50,000 already included dams or structures, with or without power generation facilities. The remaining 10,000 sites were undeveloped, although in most cases the site potential had been investigated at one time.

To select from the 60,000 sites those most appropriate for development, IWR conducted a series of four screenings. The first stage identified those projects with the physical potential for hydropower development—generally projects having a certain minimum capacity, which ranged from 50 kW in New England to 1 MW in the Pacific Northwest. About 43,000 sites were eliminated at this stage. The remaining 17,000 were then screened for preliminary economic feasibility. This second stage identified projects capable of producing enough energy to repay generation equipment costs. Only 8000 sites met this economic qualification.

The third stage combined an environmental assessment with a more detailed economic analysis. In this case economic feasibility was based on total project cost, not just the cost of the powerhouse facility. Also, more detailed hydrologic studies were made to reach a more complete estimate of site energy capability. The projects that passed the more stringent economic assessment were then analyzed for any possible environmental, social, or power-marketing constraints that might inhibit development; this time nearly 2000 sites survived.

The fourth and final stage divided the remaining sites according to near-term (before the year 2000) and long-term (after 2000) potential. In all, the NHS has identified 1948 economically feasible projects with no overriding environmental, social, or other noneconomic constraints that would preclude development; these are considered by the Corps to be the "best-candidate sites" for potential development by the year 2000. Of the sites, 1407 have existing dams and 541 are undeveloped. Together they represent a generating capacity of 46,075 MW and an average annual energy potential of 124,297 GWh.

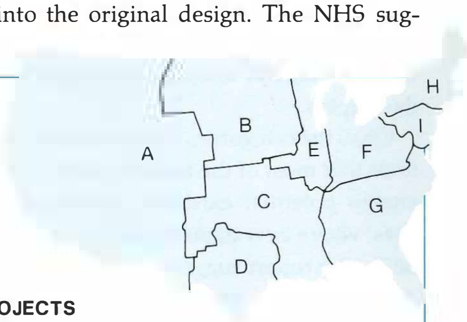
While the final list of best candidates is drastically lower than the 60,000-site list IWR started with, is the 1948 site estimate still overzealous? Michael Walsh, a civil engineer at IWR and the manager of the NHS, responds: "Shortly after the oil embargo, there was a tendency to be overly optimistic about hydroelectric power potential. I think our assessment is reasonable. We haven't underestimated the potential; yet we haven't grossly overestimated it either." EPRI and the utility industry will be reviewing the NHS report and comparing it with studies of specific regions to confirm the identification of sites and their economic and environmental feasibility.

If the nearly 2000 candidate sites are developed, would the additional power and energy be used? To address this question, the NHS researchers attempted to assess the need for hydroelectric development. On the basis of a survey of a variety of sources, the study used electricity demand growth projections ranging from 2.7% to 4.9% per year for the period 1982–2000; it also took into account estimates of the probable energy sources that will be developed over the same period. "Using the acquired data, our ranges of hydroelectric power demand suggest that if all of the NHS best-candidate sites were developed, the power could easily be absorbed into future electric utility systems," concludes Walsh.

In addition to investigating the market for hydroelectric power, the NHS researchers further defined the site inventory by dividing the 1948 candidates into four categories on the basis of ownership. The first category represents Corps dams with existing hydroelectric power facilities; the second, Corps dams without hydro facilities; the third, all non-Corps dams with or without hydro facilities; and the fourth, undeveloped sites.

After these categories were developed, the study examined how best to obtain the projected additional output from each. To realize most of the capacity and energy potential of the Corps dams already equipped with hydro facilities, the NHS report recommends that new generating units be added, existing ones be retrofitted or replaced, and water handling facilities be modified. It also recommends changes in operating policies, including the reallocation of existing storage and/or the modification of operating schedules, both annual and seasonal. While nonfederal developers could produce this additional power potential under Federal Energy Regulatory Commission licenses, the NHS expresses a preference toward Corps development of its own projects because of the higher efficiency of having only one administrative and operating entity.

Existing Corps dams without hydro facilities are attractive near-term development opportunities, the NHS report points out, particularly in cases where provisions for eventual hydroelectric power development were incorporated into the original design. The NHS sug-



NHS BEST-CANDIDATE HYDRO PROJECTS
(Results of Stage 4 Evaluation)

	Sites With Dams		Undeveloped Sites	
Region*	Number	Capacity (MW)	Number	Capacity (MW)
A	315	8,730	204	11,682
B	46	1,022	2	24
C	62	1,027	40	1,217
D	19	137	33	466
E	58†	1,244†	0†	0†
F	178	2,900	16	1,540
G	100	1,513	83	5,234
H	553	2,432	102	2,394
I	46	465	1	424
Alaska	10	17	49	3,510
Hawaii	7	9	7	29
Puerto Rico	13	35	4	24
Total	1,407	19,531	541	26,544

Source: Excerpted from *National Hydroelectric Power Resources Study*, Vol. 1.
*Regions A–I are based on North American Electric Reliability Council regions.
†Estimate.

gests that if equipped with water conveyance facilities, turbines, and generators, these sites could account for almost one-third of the additional potential capacity and energy available at all existing dams.

Most of the non-Corps sites identified are operated by the Bureau of Reclamation, the Tennessee Valley Authority, and other federal agencies, with the remainder operated by states, municipalities, and individuals. These are generally small dams or small-scale hydroelectric power sites, and they represent the majority of hydro potential at existing dams. The development of this potential power would be undertaken not by the Corps, but by other federal agencies or nonfederal developers.

Of all the categories, however, the NHS finds that most of the added capacity and energy potential exists at undeveloped sites, where new dams would have to be built. The report suggests that these sites would most likely be developed by the federal government and the states as part of multipurpose water projects, as has historically been the case.

Impediments to Development

In addition to assessing the potential attractiveness of the sites by category, the NHS addresses the attractiveness of hydroelectric power in general, highlighting issues that could act as deterrents to development. While many of these issues are not unique to hydroelectric power, they require consideration nonetheless.

The uncertainty of future electricity demand growth, for instance, may slow plans for building large projects, since justification for their construction is normally based on the need for additional peaking capacity. Legal and institutional issues, such as who will develop the sites, can also cause conflicts among potential developers. However, as Walsh explains, "Regulatory reform by the Federal Energy Regulatory Commission is helping to reduce uncertainty and clarify legal requirements for potential developers." The NHS report includes a discussion of the federal hydro regulatory system, which is complex and allows for constituency and interest group involvement. Among the other legal and institutional issues addressed are Indian rights, for example, fishing water rights.

Economic issues can also inhibit hydro development, and many of these are given attention in the NHS. The difficulty of evaluating hydroelectric power in conformance with the cost-benefit analyses required by federal authorities is noted. Historically, evaluations of federal hydropower projects have been based on cost comparisons with a most likely thermal-electric alternative. Walsh points out that the output of a hydroelectric plant can rarely be matched by any one thermal alternative, making such a comparison tenuous. "Instead a utility system's total cost with and without the hydropower project should determine the plant's real value."

The difficulty of financing the large initial capital costs common to hydroelectric projects is yet another detrimental economic factor, as is the problem of marketing power once it is produced. "The feasibility of most projects hinges on the ability of a developer to ensure a long-term buyer for the electricity produced," remarks Walsh. "This is true for nonfederal developers as well as for the Corps. The Corps has proposed new cost-sharing provisions that require local beneficiaries to finance project development costs at new Corps hydroelectric power projects."

Environmental issues were also analyzed, such as the aquatic, terrestrial, wetland, and social impacts of hydroelectric development. Hydroelectric power development does entail some environmental costs, and the NHS recommends weighing these against project benefits and exploring the possibility of mitigation measures. Walsh emphasizes, "One must also consider the environmental impacts of the alternative energy source when evaluating the direct environmental effects of hydroelectric power at a given site."

Hydroelectric development may sometimes be competing for water and land use. In these instances the decision about adding a hydroelectric facility must take into account the existing and potential future uses of that water and land, the report concludes, stressing the need for site-specific assessment.

The Next Step

In fact, the need to perform further assessments on a site-by-site basis is made clear throughout the study. "While the NHS provides a good basis for defining potential sites, the need to conduct site-specific feasibility studies to determine whether or not a single project should actually be constructed must be emphasized," Walsh comments. "When completed, the feasibility study should leave no doubt about the advisability of developing power at a site," the NHS states.

To pave the way for future feasibility studies, the Corps intends to submit recommendations based on the NHS to Congress. These recommendations will outline proposals for Corps efforts to develop hydroelectric power at its dams and will also provide support for nonfederal developers regarding Corps sites where such development is appropriate. "In either case," Walsh notes, "the Corps will continue to support the development of economically sound and environmentally compatible hydroelectric power in the United States." ■

This article was written by Ellie Hollander, Washington Office.

EPRI Offers Technical Reports Data Base

A new data base provides fast, easy access to citations and abstracts for the entire inventory of EPRI reports.

Since it opened in 1973, EPRI has published more than 4000 technical reports. Given this large output, finding the report that has just the information you need has not always been an easy task. That situation should now be alleviated with the introduction of a new computer data base by the Institute's Technical Information Division (TID). This new bibliographic file contains citations and abstracts for all EPRI technical reports, with new records added monthly to keep the data base current.

TID, in a cooperative effort with the Arizona Public Service Co., developed the technical reports file so that a comprehensive computer data base could be maintained by EPRI and distributed to member utilities. The data base is available on standard magnetic tape, which members can use on their own computer systems to enable fast and easy information access by their staffs.

Each record lists the report title and number, project manager, contractor, publication date, and page count. Also included are keywords and an abstract. An additional feature of the new data base is that for all reports published after August 1983, the file data are taken from the one-page report summaries that are distributed to announce report publication. This means that the data base can be used as a computerized index to the report summaries as well.

An on-line search can be made using any word or combination of words applicable to the subject of interest. The search will retrieve a record if a match is made anywhere in the record—from the title through the keywords and abstract.

The bibliography is now available on EPRI's computer system, and 11 utilities have requested copies of the file for their own use. Eventually, TID plans to merge this new reports file with the Electric Power Database, which contains summaries of both ongoing and completed research projects conducted by EPRI and the electric utility industry. That data base is currently available as a public file through Dialog Information Services, Inc., and can be accessed by government agencies and contractors through DOE's RECON information system.

For additional information on the new reports data base, contact Emily Breese, project manager, Technical Information Center, (415) 855-2411. ■

ET '84 Emphasizes Energy Economics

Energy financing will be the focus of the 11th annual Energy Technology Conference and Exposition, to be held March 19–21 in Washington, D.C. The 250 conference speakers will discuss how today's energy technologies can save dollars through efficient resource management and effective financing. ET '84 will also offer sessions on a variety of other topics, including current research on indoor air quality, the role of microcomputers in energy engineering, effects of the acid rain controversy on energy technology, and an assessment of future electricity availability.

Cosponsored by EPRI, the American Gas Association, the Gas Research Institute (GRI), and the National Coal Association, ET '84 is expected to attract more than 6000 registrants. The 1984 state-of-energy address, which opens the conference, will be delivered by GRI President Henry Linden. Ric Rudman, vice president for information services at EPRI, will chair this session. Secretary of Energy Donald Hodel has been invited to speak at the awards banquet, Tuesday, March 20, sponsored by the National Energy Resources Organization.

Accompanying the conference will be a 250-booth exposition highlighting energy hardware, systems, and services of interest to energy and utility industry professionals. This year's event will also feature eight post-conference courses, including two on energy financing. ■

Texas Facility Will Test Cooling-Tower Performance

Late in 1983 EPRI began construction of the electric utility industry's first test facility for assessing the performance of evaporative cooling towers. The $1 million facility is being built at Houston Lighting & Power Co.'s Parish station near Houston, Texas. It will permit utility testing and evaluation of both conventional and advanced evaporative towers.

John A. Bartz, manager of EPRI's heat rejection subprogram, says the project will develop improved procedures for establishing cooling-tower specifications and for helping utilities evaluate bids for new or retrofitted cooling towers. "This project will be of great help to electric utilities in specifying new, more energy-efficient cooling towers," Bartz notes, "because it will permit new procedures derived from EPRI research to be verified under actual operating conditions."

A group of seven utilities is funding the work along with EPRI: Houston Lighting & Power, Indianapolis Power & Light Co., Pacific Gas and Electric Co., Public Service Co. of Oklahoma, Southern California Edison Co., Southern Company Services, Inc., and the Tennessee Valley Authority (TVA). Other utility participants are also being sought.

The principal contractors for the project are Battelle, Pacific Northwest Laboratories, which designed the facility and will oversee construction; Environmental Systems Corp., which specified instrumentation, designed the test plant, and will operate the facility; and TVA (Norris Engineering Laboratory). All three contractors will be involved in the analysis of test data.

Bartz notes that extensive thermal and hydraulic performance testing will be conducted at the new facility through 1985. "Project managers," he says, "hope this effort will ultimately eliminate the economic penalties utilities pay for towers with inadequate cooling capacities." ■

EPRI Completes Study of PCB-Related By-Products

There has been speculation about the potential presence and formation of polychlorinated dibenzodioxins (PCDDs) and polychlorinated dibenzofurans (PCDFs) during the combustion of electrical equipment that contains polychlorinated biphenyls (PCBs). Until recently, however, chemical and toxicological information on these two substances had not been systematically evaluated.

EPRI has published the first large-scale scientific review of available information concerning the existence of PCDDs and PCDFs in utility transmission and distribution equipment. To produce this state-of-the-art review, CS-3308, the investigators drew on leading dioxin and dibenzofuran researchers around the world, as well as on transformer service companies, manufacturers, and utilities. "The information in this report should help utilities separate fact from conjecture about these substances and their formation," comments EPRI Project Manager Ralph Komai.

The report concludes that the formation of PCDDs and PCDFs in electrical equipment under normal operating conditions is unlikely. However, fires in or around PCB-containing equipment can lead to the formation of PCDFs and, to a lesser extent, PCDDs. Also expected to be of interest to utilities is the fact that sparks and soldering apparently do not cause PCDFs to form from PCBs, although welding does.

In addition to publication of the new report, EPRI sponsored a PCB seminar in Atlanta, Georgia, in December 1983. More than 400 people attended the seminar, which was conducted by members of EPRI's PCB interdivisional working group and which featured experts from utilities, research organizations, and commercial firms. Papers presented at the seminar discussed methods of detecting and destroying PCBs, as well as PCB fires and PCDF and PCDD formation. The proceedings will be published in mid 1984.

Meanwhile, plans are under way at EPRI to document cleanup practices following fires that involve PCBs. This will complement research projects that are measuring PCDF concentrations in old equipment and simulating the conditions under which PCDFs form. ■

Progress Report Zeroes in on New Technologies

The 1983 edition of *Progress on Significant R&D Projects* (RA-2733-SR) is now available from EPRI. This document provides important information to utilities, manufacturers, architect-engineers, and other suppliers about technologies that are nearing commercial availability.

The progress report lists 29 major projects with an EPRI authorization of $5 million or more and 114 projects authorized for less than $5 million. The smaller projects are expected to yield products of tangible benefit to utilities within the next two years.

Many of the projects described are aimed at developing future systems for the generation, transmission, distribution, and end use of electricity; others address complex safety and environmental issues. In addition, the report reviews 39 analytic, experimental, and bench-scale studies that have been influential in confirming or redirecting EPRI's research programs.

The project descriptions are grouped into six research areas: fuel processing, electric power generation, transmission and distribution, energy storage and management, energy analysis, and environmental control and assessment. Each description covers project progress to date, value to the industry, keywords pertinent to the project, product name, anticipated date of availability, research category, and the EPRI division responsible for the project.

A companion volume to this progress report is the 1983 edition of *Research Results and Applications* (RA-2732-SR), which describes products that became available for utility use in 1982. Both reports are available through the Research Reports Center at no charge to EPRI members. The price for nonmembers is $20 a copy. ■

CALENDAR

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

MARCH

6–7
Seminar: Indoor Air Quality
Atlanta, Georgia
Contact: Gary Purcell (415) 855-2168

14–16
Solar and Wind Power: 1984 Status and Outlook
San Diego, California
Contact: Edgar DeMeo (415) 855-2159

15–16
Residential Off-Peak Cooling
Tempe, Arizona
Contact: Veronika Rabl (415) 855-2401

APRIL

9–11
3d International RETRAN Meeting
Las Vegas, Nevada
Contact: Lance Agee (415) 855-2106

MAY

1–2
Seminar: Indoor Air Quality
Denver, Colorado
Contact: Gary Purcell (415) 855-2168

1–3
Annual Review of Demand and Conservation Program Research
Atlanta, Georgia
Contact: John Chamberlin (415) 855-2415

1–3
Mutual Design of Transmission Lines and Pipelines
Palo Alto, California
Contact: John Dunlap (415) 855-2305

9–10
Meeting: 14th Semiannual ARMP Users Group
Jackson, Michigan
Contact: Walter Eich (415) 855-2090

15–17
Mutual Design of Transmission Lines and Railroads
Chicago, Illinois
Contact: John Dunlap (415) 855-2305

JUNE

4–7
Symposium: State of the Art of Feedwater Heater Technology
Washington, D.C.
Contact: Isidro Diaz-Tous (415) 855-2826

19–21
Mutual Design of Transmission Lines and Railroads
Washington, D.C.
Contact: John Dunlap (415) 855-2305

JULY

17–19
Annual Review of Demand and Conservation Program Research
Seattle, Washington
Contact: John Chamberlin (415) 855-2415

SEPTEMBER

11–13
Mutual Design of Transmission Lines and Railroads
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

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

OCTOBER

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

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

EDS FIELD TESTS

As coal-derived and shale liquids from pilot plants have become available in greater quantities, researchers have been investigating their potential use as an alternative to petroleum products in utility power generation. Tests in full-scale equipment have been particularly important as a means of revealing unexpected operating characteristics that might not show up in the laboratory. Field tests to date have evaluated the performance, emission, and handling characteristics of several synthetic liquid fuels, including methanol and SRC-II (solvent-refined coal) in utility boilers and methanol and hydrotreated shale oil in utility gas turbines. This report discusses two EPRI-sponsored projects (RP2049 and RP2112-4) to evaluate the performance of an Exxon Donor Solvent (EDS) middle-distillate fuel in a 3.5-MW(e) utility diesel engine and an EDS full-range distillate in a 44.5-MW (e) wall-fired boiler. In relation to oil and gas fuels, the EDS coal-derived liquids showed promising performance and produced generally comparable emissions.

Diesel testing

Laboratory Testing The first EDS field test—cofunded by EPRI, the Easton Utilities Commission (Easton, Maryland), and the American Public Power Association—evaluated a middle-distillate EDS liquid as a potential utility diesel engine fuel. Table 1 compares the properties of this fuel with those of the baseline diesel fuel. Before the field test Southwest Research Institute conducted laboratory tests using the EDS liquid.

The laboratory tests were performed on a turbocharged four-stroke, 12-cylinder, medium-speed (900-rpm) locomotive engine manufactured by General Electric Co. The researchers modified one cylinder of the engine to allow pilot injection of diesel oil for ignition assistance; the EDS, which has a low cetane number (21), could not be burned alone in a pure diesel mode without such assistance. The other 11 cylinders burned No. 2 diesel fuel (DF-2) throughout the test. The General Electric engine has a 12.7 compression ratio with a cylinder displacement of 668 in^3 (10,946 cm^3); it is rated at 2500 brake horsepower (bhp) at 900 rpm. The test cylinder, which has a 9-in (22.9-cm) bore and a 10.5-in (26.7-cm) stroke, was instrumented to permit monitoring of cylinder pressure and ignition characteristics.

A test program was designed for gathering data from the test cylinder, which burned either neat synfuel with DF-2 pilot injection assistance or blends of EDS and DF-2. Blends with 30% EDS and 50% EDS were used. Tests were conducted at full load (500 bhp at 536 rpm and 2500 bhp at 1050 rpm). In the runs with pilot injection, the DF-2 entered the test cylinder through the pilot injection nozzle, while the primary charge (of EDS) entered through the main injection nozzle. The pilot injection timing was varied to minimize knock, but the EDS injection timing was held constant at the standard General Electric setting.

The test cylinder was controlled at a given operating point by setting its fuel-derived heat input equal to one-twelfth of the total engine fuel-derived heat input. Cylinder pressure and its rate of increase, indicated horsepower, and exhaust gas temperature and composition were observed.

The results of this laboratory work demonstrated that DF-2 pilot injection allowed the EDS to be burned neat in the otherwise unmodified cylinder. At 1050 rpm and full load, power levels within 1% of baseline levels were achieved with a pilot injection rate of 5% of cylinder fuel heat input. Optimal pilot injection timing at 1050 rpm was about 70° (or 12 ms) before top dead center. With this timing, however, some light audible knock was observed. Pilot injection timing at 536 rpm also appeared to be optimal at about 12 ms before top dead center.

The fuel blend with 50% EDS could be burned without excessive knock and with approximately baseline-level horsepower. When the 30% EDS–70% diesel oil blend was burned, no knock was observed. For a given blend ratio or a given pilot injection rate (i.e., percentage of fuel-derived heat input), tests at 536 rpm produced more severe knocking tendencies than tests at 1050 rpm. This is attributable to a lower cylinder compression temperature, which results from greater time for ring leakage and heat loss to the cylinder wall and from the lower turbocharger output corresponding to lower engine speed. The lower cylinder temperature allowed more fuel from the main charge to enter the cylinder before ignition was initiated. The subsequent rapid ignition produced knock.

Attempts to determine single-cylinder emissions were hampered by the pulsating exhaust gas pressure in the exhaust manifold. Because of difficulties in segregating the test cylinder exhaust from that of the adjacent cylinders without extensive manifold modification, it was impossible to accurately determine the composition of the exhaust gas.

Field Testing Using the laboratory test results, Cooper Energy Services developed a test program for a 360-rpm Cooper-Bessemer engine driving a 3.5-MW (e) generator at the Easton Utilities Commission. Cooper and Easton performed the site adaptation engineering and conducted the engine field tests; Battelle, Columbus Laboratories performed emission tests in the field; and Control Data Healthcare Services of Rockville, Maryland, carried out an industrial hygiene program to ensure safe handling of the synfuel.

The test engine is a 16-cylinder turbocharged engine, with a cylinder bore of 15.5 in (39.4 cm) and a stroke of 22 in (55.9 cm). One cylinder head was modified to accommodate a spark–natural gas ignition unit. The researchers also instrumented the cylinder for pressure and exhaust temperature measurement and installed a sampling device for monitoring cylinder emissions. The turbocharger after-cooler water flow was manually varied to control the air manifold temperature.

The test program called for all tests to be performed at 360 rpm, which is the synchronous speed of the machine. The variables were engine load (full speed at no load, 1800 kW, 2600 kW, and 3600 kW); EDS/DF-2 fuel blend (25%, 66.7%, and 75% EDS); and air manifold temperature (95, 110, 150°F; 35, 43, 66°C). Unblended DF-2 was used as a baseline fuel. Fuel blends were tested in both single-cylinder and full-engine tests. The 75% EDS blend was used only in single-cylinder tests because of the unacceptable knocking levels it produced.

Also, some single-cylinder tests were run with unblended EDS, with a spark–natural gas ignitor providing about 3% of the fuel-derived cylinder heat input at full load. These tests showed that pure EDS could be successfully burned in a diesel engine modified with such an ignitor. Engine efficiency under this operating condition was comparable to that obtained with the baseline fuel. At lower loads the constant ignitor gas flow setting provided a higher percentage of cylinder heat input. In all of the single-cylinder tests using neat EDS, the spark ignitor timing was set to produce the minimum rate of pressure increase from the main charge ignition.

Results from tests with the blended fuels indicate that the full engine can operate on blends containing up to 65% EDS without excessive knock when the air manifold temperature is 150°F (66°C). The 66.7% EDS blend resulted in an engine heat rate 1.02 times greater than that with DF-2. Emission tests at full load with the 66.7% EDS blend indicated that carbon monoxide, carbon dioxide, and nitrogen oxide (NO_x) levels were not significantly higher than those produced with 100% DF-2. Sulfur dioxide emissions were lower because of EDS's low sulfur content. Total hydrocarbon emissions were 40% lower, and the total particulate level was 74% higher.

Blends of EDS and DF-2 form a waxy precipitate that can pass through 20-μm filters but that clogs 5-μm filters. More precipitate formed with the 50% EDS blend than with the 66.7% EDS blend, which suggests that DF-2 contributes to the precipitation.

Increasing the air manifold temperature significantly reduced the knock produced by EDS blends. (Transamerica Delaval, Inc., noted a similar trend when it tested SRC-II liquids in one of its engines.) Researchers found that the combustion performance of 100% EDS and EDS blends does not improve in comparison with DF-2 performance as engine load decreases; therefore, derating would not increase an engine's ability to burn blends containing larger proportions of EDS.

Though industrial hygiene requirements are more stringent for EDS than for DF-2, the more complex EDS handling procedures did not materially affect crew efficiency. The crew was not exposed to the fuel during the tests, and no adverse health effects appeared or are expected.

The limited test time makes it difficult to determine the possible long-term effects of EDS on engine parts or lube oil. The only potentially harmful materials effect noted was the deposition of a varnish-like coating on the metal surfaces wetted by the fuel. Because rubber-based elastomers are attacked by EDS, those wetted by the fuel were replaced with EDS-resistant Viton or Teflon before the test.

Overall, the test results indicate that EDS could be a viable diesel fuel, given some engine modifications and changes in operating procedures to improve its combustion characteristics. Possible modifications include combustion chamber design changes, ignition assistance systems, pilot diesel fuel injection, increased air manifold temperature, and timing optimization. No attempt to optimize synfuel firing conditions through engine modification was made, since that was beyond the scope of the project. This test series is reported in detail in EPRI AP-3224.

Table 1
LIQUID FUEL PROPERTIES

	EDS Diesel Fuel	No. 2 Diesel Fuel	EDS Boiler Fuel	Petroleum Boiler Fuel
Composition				
Carbon (wt%)	88.35	86*	88.89	87.01
Hydrogen (wt%)	10.20	13*	9.67	12.46
Nitrogen (wt%)	0.077	0.005*	0.22	0.19
Sulfur (wt%)	0.007	0.15*	0.045	0.17
Ash (wt%)	0.005		0.003	0.003
Oxygen (wt%)	0.99	0.8*	1.17	0.16
Higher heating value (Btu/lb)	18,569	19,500*	18,180	19,233
Lower heating value (Btu/lb)			17,300	18,097
American Petroleum Institute gravity at 60°F (15.6°C)	16.5	37.1	13.5	25.03
Specific gravity	0.956	0.8393	0.9759	0.9040
Distillation range, °F (°C)	376–695 (191–368)	386–650 (197–343)		
Cetane number	21	49.6		

*Nominal value.

Boiler field test

Another full-scale test, cofunded by Southern California Edison Co. (SCE), evaluated the performance of EDS full-range distillate fuel in a balanced-draft, six-burner, front-wall-fired 44.5-MW (e) Combustion Engineering boiler in a nonreheat plant in Colton, California. The boiler—which produces 425,000 lb/h (53.5 kg/s) of steam at 1250 psig (8.6 MPa) and 950°F (510°C)—is the same dual-fuel (oil-gas) unit used in an earlier SCE–EPRI cofunded test to evaluate methanol as a utility boiler fuel (AP-2554).

To perform the EDS test, SCE used Viton to replace the rubber-based elastomers in the methanol fuel system's piping, valves, and tank floating roof seal; modified the burner tips for improved atomization; changed the high-pressure methanol fuel pump internals to accommodate the reduced volumetric flow required for EDS; strengthened fuel spill prevention measures; and instituted an industrial hygiene program. Test personnel also sealed casing leaks in the boiler, calibrated the combustion air venturis, and installed instrumentation in the boiler's convection passes and the stack gas breeching for monitoring temperature and emissions.

The SCE crew carried out the technical test program under the functional direction of Energy and Environmental Research Corp. Approximately 4500 barrels of EDS were consumed. To obtain baseline data, the test program also included runs with natural gas and a petroleum distillate blend closely resembling No. 4 oil. The boiler was operated through a range of loads for each fuel tested. Table 1 presents the properties of the EDS and petroleum fuels.

A low-NO_x firing technique involving a burner out of service was used to evaluate the potential for NO_x reduction when firing EDS. (EDS has a higher fuel-bound nitrogen content than No. 4 oil.) The firing mode features fuel-rich operation in the near-flame zones, which lowers available oxygen and peak flame temperature. After the initial combustion productions have lost heat to the furnace walls, combustion is then completed by air addition. The burners remaining in service require an increased fuel flow in order to maintain boiler load, while the burner out of service experiences a slightly higher air flow as a result of the lower pressure drop across it in the absence of flame. This configuration serves to enhance the near-flame-zone rich burning of the active burners and provides supplemental combustion air after rich burning has taken place.

The performance of EDS in the boiler was consistent with predictions based on its properties. Boiler efficiency (as determined by the ASME heat loss method) was higher with EDS than with the gas or the baseline fuel oil because the synfuel's lower hydrogen content resulted in a lower water loss in the stack gas. The higher flame luminosity of EDS produced higher furnace heat absorption and hence lower gas temperatures in the boiler's convection passes and lower superheat temperatures. Since superheat temperature affects steam turbine thermal efficiency, the net effect was a slightly higher unit heat rate, even though boiler efficiency was improved.

Table 2
PERFORMANCE AND EMISSIONS RESULTS

	EDS	Oil	Gas
Boiler thermal efficiency at nominal full load (%)*	88.83	88.01	84.45
Gross load (MW)	42.4	42.7	41.9
Average heat input (million Btu/h)	491.2	488.9	495.6
Average heat rate (Btu/kWh)	11,583	11,460	11,828
NO_x emissions at full load*			
NO_x at 3% oxygen (ppm)	264	240	265
NO_x (lb/million Btu)	0.349	0.311	0.322

*Nominal heat input = 490 million Btu/h; nominal excess air = 15%.

Table 2 presents the performance results. In summary, boiler performance with EDS was comparable to that with the baseline oil, and thermal efficiency was slightly higher with EDS. Excess air requirements, maximum attainable boiler load, and power generation heat rate with EDS were all comparable to those with oil.

The emissions monitored were carbon monoxide, hydrocarbons, NO_x, smoke, total particulate loading, and submicrometer particulates. Firing EDS instead of oil or natural gas produced no increase in carbon monoxide and hydrocarbon emissions. Both EDS and oil firing produced higher NO_x with increased heat input rate, with EDS producing about 10% higher NO_x than oil (Table 2). Gas firing produced a sharper rate of NO_x increase with heat input rate than did either EDS or oil. Low-NO_x (i.e., burner-out-of-service) operation with EDS reduced NO_x emissions 20% below the level produced by EDS firing with all burners in service and minimum excess air. This technique resulted in a similar NO_x reduction for oil firing.

Bacharach smoke numbers were comparable for EDS and oil under normal firing conditions. For each fuel the number increased with reduced load and low-NO_x operation, though it increased at a slightly higher rate for EDS. EDS firing resulted in lower particulate emissions than oil firing; these emissions increased slightly at low load. No visible smoke was produced. An electrical aerosol analyzer was used to measure submicrometer particulates. The results indicated a bimodal size distribution for EDS, with one mode centered at 0.015 μm and another at 0.25μm. EDS produced a significantly higher submicrometer particle count than did oil.

In summary, EDS appears to be a technically viable boiler fuel. Its performance is generally comparable to oil's, and it produces comparable emissions, with significantly lower SO_x emissions. Though additional industrial hygiene safeguards are necessary for EDS, the test operators encountered no significant inconvenience or hardship in handling and using the fuel. *Project Manager: Henry Schreiber*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

IN-FURNACE SO_2 CONTROL FOR PULVERIZED-COAL BOILERS

Furnace sorbent injection is currently under development as a potential sulfur dioxide (SO_2) control approach for coal-fired utility boilers. In this process a pulverized calcium-based material (such as limestone) is injected directly into the furnace cavity of a coal-fired boiler. Upon entering the furnace the sorbent rapidly decomposes into lime, which reacts in suspension with SO_2 to form solid calcium sulfate. The calcium sulfate and unreacted sorbent particles are then removed, along with the fly ash, in conventional particulate control devices. In essence, the process attempts to apply the SO_2 sorbent chemistry of fluidized-bed combustion to conventional pulverized-coal boilers. Because of its conceptual simplicity, the process has promise for capital cost savings over conventional flue gas desulfurization systems. EPRI is supporting several projects aimed at optimizing SO_2 removal, resolving potential power plant integration issues, and further defining costs.

In the early 1960s the injection of sorbent directly into the furnace of a utility boiler was explored as a means of reducing SO_2 emissions without sophisticated chemical flue gas treatment systems (Figure 1). At that time direct limestone injection in conjunction with, for example, wet particulate scrubbing was considered the least complicated and most economical procedure for meeting anticipated SO_2 and particulate removal requirements. However, various trials of this concept at small-scale furnaces and full-scale utility boilers in the United States, Europe, and Japan generally failed to demonstrate sufficient in-furnace SO_2 removal at practical sorbent-to-sulfur ratios.

SO_2 removal during tests at utility boilers typically ranged from 15% to 40%, well below the target values of 80–90%. The removal efficiency was found to be highly dependent on the design and operating conditions of the boiler, as well as on the type of sorbent and injection system used. In addition, the potential for adverse effects on boiler performance surfaced during these early test programs. Most notably, utilities reported increases in furnace water-wall slagging, fouling of convective passes, and degraded performance of electrostatic precipitator (ESP) particulate controls. Because of the low, variable SO_2 removal efficiency and the boiler operating concerns, further process testing was abandoned by the early 1970s, and the development of wet scrubber systems became the primary focus of SO_2 control efforts.

A variety of factors have contributed to a renewed interest in furnace sorbent injection. Foremost among these is recent experimental work in the United States and West Germany that indicates the possibility of achieving higher SO_2 removal efficiencies at practical sorbent injection rates if combustion and sorbent conditions are properly controlled. New combustion systems being developed to control nitrogen oxide (NO_x) emissions may help achieve the necessary conditions. The controlled mixing conditions associated with low-NO_x combustion may enable optimization of the sorbent injection process—and hence the simultaneous control of NO_x and SO_2.

Another factor contributing to the resurgence of interest in dry sorbent injection is

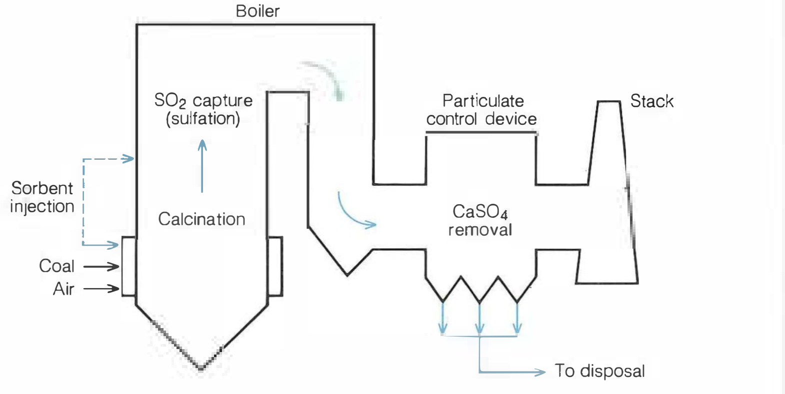
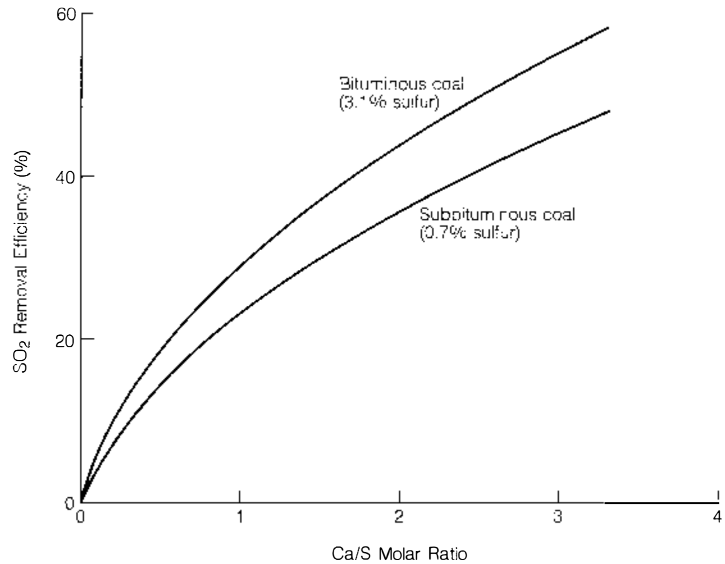


Figure 1 In the furnace sorbent injection process, limestone or other alkaline materials are injected directly into the furnace of a coal-fired boiler. Within fractions of a second, the limestone decomposes into reactive lime particles (calcination), which then chemically react in suspension with SO_2 (sulfation) to form solid calcium sulfate ($CaSO_4$). The calcium sulfate, together with unreacted lime and fly ash, is removed from the flue gas by the particulate control device.

the growing incentive for developing low-cost incremental SO_2 controls applicable to both existing and new power plants. The potential also exists for combining furnace sorbent injection with other SO_2 control technologies. For instance, its use in conjunction with coal cleaning or coal blending may provide flexibility in achieving SO_2 emission compliance or may allow the purchase of cheaper, higher-sulfur coals for existing units. Also, the integration of this process with other flue gas treatment systems may provide an overall SO_2 control capability adequate to meet higher requirements for new plants.

Figure 2 Pilot tests of furnace limestone injection were conducted with two coals to determine SO_2 removal efficiency as a function of the calcium/sulfur (Ca/S) molar ratio. Pulverized limestone was injected through overfire air ports located away from the burner zone. Probes located in the furnace indicated that at temperatures of 2200–2400°F (1204–1316°C), the calcination and sulfation reactions were essentially completed in less than one second.



Process development

To confirm the SO_2 removal potential of sorbent injection, Mitsubishi Heavy Industries (MHI) performed pilot testing under RP1836-1. These initial proof-of-concept tests were conducted on a 23-MW (th) test furnace (80 million Btu/h) equipped with a low-NO_x burner developed by MHI. Earlier work under RP1836-1 to verify the burner's NO_x control performance had established that temperature and combustion conditions in this furnace closely simulate those of an actual utility boiler.

The sorbent injection testing was intended to demonstrate SO_2 removal (without attempting to optimize process conditions) and to provide a preliminary indication of the influence of major process and combustion parameters. The two coals selected for the tests were a Japanese high-sulfur bituminous coal (3.1% sulfur) and a low-sulfur western U.S. subbituminous coal (0.7% sulfur). A high-calcium limestone was used as the sorbent.

Initial screening tests evaluated several sorbent injection locations in the furnace. These included the burner's coal and secondary air nozzles and separate ports downstream of the burner zone. Injection through separate overfire air ports was found to be the most effective approach. Figure 2 shows typical results for both coals for a range of limestone injection rates (expressed as the calcium/sulfur, or Ca/S, molar ratio).

For the bituminous coal, SO_2 removal was over 40% at a Ca/S molar ratio of 2 and approached 60% at a Ca/S ratio of 3; these levels correspond to a calcium utilization of about 20%. The SO_2 removal efficiency for the subbituminous coal was consistently lower at equivalent Ca/S ratios. Other parameters, including limestone fineness, furnace excess oxygen, and coal firing rate, influenced SO_2 capture but to a lesser extent than sorbent injection location and the Ca/S ratio.

To complement the pilot tests, MHI also conducted a series of bench-scale experiments to examine SO_2 capture under idealized laboratory conditions. These tests used a small flow reactor in which pulverized limestone and synthesized flue gas can be mixed and reacted while fundamental parameters (e.g., reaction temperature, sorbent-SO_2 contacting time, and initial SO_2 concentration) are independently varied. The results indicated that there are optimal combinations of temperature and reaction time that maximize SO_2 capture for a given sorbent material. The highest SO_2 removal efficiencies—over 80% (at a Ca/S ratio of 2)—were observed at the longest reaction time tested (1.5 s) and at temperatures near 1850°F (1010°C). At higher temperatures approaching those encountered in the upper regions of a utility furnace (2000–2200°F; 1093–1204°C), SO_2 removal efficiencies were similar to levels observed in the pilot furnace. The effects of SO_2 concentration and limestone fineness observed in the pilot testing were also duplicated, which further affirmed the validity of the flow reactor experiments.

The final flow reactor tests investigated the chemical mechanisms involved in the sulfur removal process. In one experiment removal efficiencies were compared when sulfur was present as a reduced sulfide (H_2S) as opposed to SO_2. The removal efficiency with H_2S was about half of that obtained with SO_2. These results suggest that attempts to optimize SO_2 removal by injecting sorbent into furnace regions where H_2S could be prevalent, such as reducing zones close to the burners, may not be a preferred approach.

The MHI pilot- and bench-scale work verified the potential of furnace sorbent injection for SO_2 control and provided insights into the SO_2 removal process. However, these programs and other research efforts in the United States and abroad have also identified major gaps in the current understanding of the process's mechanisms and applicability. For example, serious questions still remain about the most effective way to improve calcium utilization and about process design criteria for the range of furnace conditions encountered in the utility boiler population. Such questions need to be resolved before full-scale application of the process can proceed.

To complete process development, EPRI

has initiated a jointly funded project with Southern Company Services, Inc. (RP2533-1). This effort involves further bench and pilot testing to develop design guidelines for utility boiler applications. The tests are investigating furnace sorbent injection alone and in combination with dry back-end flue gas treatment processes. They are being conducted by two subcontractors, the Southern Reseach Institute and KVB, Inc., and are scheduled for completion in early 1985.

Power plant impacts

The introduction of limestone or other SO_2 sorbents into the furnace will alter the chemical and physical properties of the fly ash and also increase the quantity of solids passing through the boiler. For example, at a limestone injection rate corresponding to a Ca/S ratio of 2, total solids loading will increase 25% for a coal containing 0.5% sulfur and 10% ash and will nearly triple for a coal with 4% sulfur.

A review of earlier utility experience with this technology—which was conducted by Combustion Engineering, Inc. (C-E), as part of a preliminary retrofit feasibility study—identified several possible power plant impacts. Among the most important are increased slagging and fouling deposits on furnace heat transfer surfaces, degraded ESP performance, and increased ash handling and disposal requirements. A major objective of EPRI's current research is to determine the extent of these effects and to develop corrective measures as necessary.

Under RP899-2 C-E conducted pilot combustion tests at its Fireside Performance Test Facility (4 million Btu/h) to measure the slagging and fouling properties of fly ash produced during limestone injection. This facility simulates the geometry, temperature ranges, and velocities characteristic of a utility boiler's convective section, as well as the thermal environment of the radiant furnace walls. The tests examined two coals with different ash properties, representing a range of slagging and fouling behavior encountered in the utility industry. The first coal, a high-iron midwestern bituminous coal (3.4% sulfur), typically exhibits high slagging and moderate fouling tendencies. The second coal, a high-sodium western subbituminous coal (0.5% sulfur), exhibits high fouling and moderate slagging behavior.

The work focused on measuring the chemical and physical properties of the deposits, including chemical composition, deposit accumulation rate, deposit bonding strength, heat transfer effects, and ease of removal (deposit cleanability). C-E then used these measurements to predict the impact of furnace limestone injection on boilers firing these two coal types.

For both coals the increased mass loading during limestone injection resulted in a greater rate of fouling deposit accumulation on the convective tubes. However, because of increased deposit friability and lower deposit-to-tube bonding strength, deposit cleanability was improved and the effectiveness of conventional soot blowing enhanced. In the case of the western subbituminous coal, limestone injection may even alleviate the severe fouling problems commonly encountered. In general, it appears that the increased fouling deposit accumulation rates with limestone addition can be managed by conventional soot-blowing equipment, although increased blowing frequency and/or additional blowers are likely to be required.

Limestone injection also increased the quantity of slagging deposits on the radiant walls and affected their physical characteristics. It resulted in a drier, more friable deposit that was more easily removed by conventional soot blowing. Again, overcoming the increased amount of deposits will probably require more frequent soot blowing or even the installation of additional blowers.

A significant result of the C-E work was the demonstration of a laboratory procedure for determining the slagging and fouling consequences of furnace limestone injection. The results for the two test coals are instructive regarding the general impact of limestone injection on boiler heat transfer surfaces. Given the variability of coal properties, however, utilities considering this technology for retrofit are advised to conduct similar screening tests on the specific coals to be used. Engineering studies will also be necessary to account for such unit-specific factors as furnace design, convective tube spacing and geometries, soot blower coverage, and ash handling capabilities.

Economics

The capital and operating costs of furnace limestone injection have been estimated by C-E (RP1836-3) and Stearns-Roger Engineering Corp. (RP1682-1) for new and retrofit applications. For new 500-MW boilers equipped with fabric filter particulate controls, the incremental capital cost estimates range from \$15 to \$30/kW, depending on coal sulfur content and the Ca/S ratio. The major portion of this cost is associated with limestone delivery, storage, pulverization, and injection (including combustion system design modifications), which represent additional plant components not otherwise needed.

For retrofit applications the capital cost can be considerably higher because of the probable need for upgrading soot-blowing systems, ESPs, and ash handling and disposal systems. Such costs are site-specific but could result in total retrofit capital costs two to three times the new unit costs.

The operating costs increase nearly proportionately to coal sulfur content. This reflects the fact that higher-sulfur coal requires greater quantities of raw sorbent and produces more by-product for disposal, both of which represent major operating cost items. For Ca/S ratios between 2 and 3, 30-year levelized operating costs are about 3–5 mills/kWh for a 0.5% sulfur coal and increase to 8–12 mills/kWh for a 4% sulfur coal. As research further defines the process design and plant upgrading requirements, refinements in these preliminary cost estimates will be possible.

Future research

In addition to the research described here, results from other EPRI projects are expected to be applied to sorbent injection technology. Low-NO_x-burner evaluations by Riley Stoker Corp., Babcock & Wilcox Co., C-E, MHI, and KVB are aimed at demonstrating retrofit NO_x combustion control systems and providing guidelines for their application (RP1836, RP2154). If such systems are shown to be essential to the sorbent injection process, the results from these efforts will play a key role in its commercial application. Also, results from flue gas conditioning tests for enhancing ESP performance (RP724-2) will be applicable in cases where the retrofitting of furnace sorbent injection requires upgraded particulate controls.

These studies, together with the process development, boiler impact, and economic evaluation efforts discussed above, will provide the groundwork for prototype testing of sorbent injection in coal-fired utility boilers. The retrofitting of several boilers in the 40–100-MW (e) range is the next logical step toward determining the commercial potential of this process. Such retrofits will enable final optimization and verification of the process design and will also allow economical resolution of any plant impact issues not fully dealt with in laboratory testing.

Experimental work at the prototype scale will address upgraded ESP options; long-term process effects on furnace slagging, fouling, and erosion; alternative sorbent injection systems; and ash handling and disposal requirements. EPRI is currently soliciting utility interest in participating in up to four prototype test programs expected to start as early as 1986. *Project Managers: Michael McElroy and David Eskinazi*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

TRANSMISSION SUBSTATIONS

Advanced operating mechanism for switching devices

Operating experience shows that mechanism malfunction is the cause for 50% of the failures of power circuit breakers to operate on command. Most of the problems involve the pneumatic or hydraulic systems that supply the mechanism operating energy. An energy source that does not require these auxiliary systems could greatly improve equipment reliability and—by eliminating storage reservoirs and air compressors or hydraulic pumps with their drive motors and controls—reduce mechanism system maintenance and auxiliary power requirements. Thus RP1719 was initiated to find a highly reliable, simple energy source for substation switching devices, and to develop an operating mechanism for transmission-class SF_6 puffer circuit breakers that use this energy source.

Early project work showed that a chemical-propellant energy source could meet the requirements of all substation switching devices. A small charge is used as a gas generator to operate the piston of a compact direct-drive mechanism. The investigation indicated that one charge, about the size of a 12-gage shotgun shell, could meet the operating energy requirements for a mechanism applicable to puffer-type SF_6 circuit breakers rated 121–800 kV. The energy output is consistent over an ambient temperature range of -40 to 115°F (-40 to 46°C), so that cold weather operation would not be a problem.

The mechanism uses a solenoid to initiate percussion firing of the charge, and because it can provide peak pressure to start operation much faster than is possible with pneumatic systems, high-speed breaker operation would be easier to achieve. The charge storage capacity enables 25 opening and 25 closing operations to be performed without reloading the charge storage magazines. Charges can be placed in the magazine at any time without taking the breaker out of service.

The prototype design demonstrates the simplicity of the device. By eliminating the auxiliaries required for hydraulic and pneumatic mechanisms, it should provide more reliable operation and reduced maintenance costs. The commercialization potential of the mechanism is now being evaluated. Also, a final report covering the project's progress through the building of the breaker mechanism prototype is being prepared. *Project Manager: Narain G. Hingorani*

Arc interruption in gas flows

The most difficult part of the arc interruption process in a gas blast interrupter occurs in a brief period around current zero. It is during this thermal interruption period of a few microseconds that the arc path must be cooled sufficiently to change it from a conducting path to an insulating one that can withstand the system recovery voltage. Since 1974 EPRI has sponsored an investigation of ways to improve the thermal interruption performance of axial gas flow interrupters (RP246).

The objective of this project was to study the effects of various interrupter design parameters (parameters under the control of the design engineer) on the thermal interruption process. Most experiments were conducted on two-pressure model interrupters with a special test circuit designed to provide the desired rate of change of current (di/dt) at current zero. Work in the last phase of the program, which examined the effects of nozzle blocking by the current, was conducted on a small puffer breaker or similar test interrupters. To obtain data on various aspects of the interrupting process, it was necessary to develop new diagnostic techniques. These have proved valuable not only for this project but also to theoreticians studying the arc interruption process.

The researchers measured how thermal interruption performance was affected by changes in interrupter geometries, such as nozzle shape, contact location in relation to nozzle throat, upstream gas flow path, and upstream-to-downstream pressure ratio. They also developed and verified computer programs for showing gas flow fields in the subsonic upstream region and the reestablishment of flow after deblocking of the nozzle by the arc. Interferometric techniques for measuring arc core diameter and arc mantle thickness were developed to provide information on the arc near current zero. High-speed photography (two pictures per microsecond), together with measurements of voltage gradients along the arc column, helped in identifying the arc segments most affected by the gas flow. Improved measurements of the post-arc current in the few microseconds after current zero provided a better understanding of the cooling process in the arc path.

The experiments conducted on the small puffer-type circuit breaker provided considerable data on how nozzle blocking by the current affects interrupting performance. Other efforts examined how nozzle blocking affects nozzle ablation during the interrupting process.

Together, these results provide a better insight into the dynamics of axial gas flow interrupters and serve as a valuable tool to the switchgear designer. Earlier project work was reported in EPRI EL-284 and EL-1455. The final phase is covered in EL-3293, to be published soon. General Electric Co. was the principal contractor; the State University of New York at Buffalo, Rensselaer Polytechnic Institute, and Hitachi, Ltd., were subcontractors. *Project Manager: Narain G. Hingorani*

DISTRIBUTION

Forced cooling by EHD pumping

It has been known for some time that the application of electric fields can create movement of insulating fluid. This effect has been termed electrohydrodynamic (EHD) pumping. Recently, General Electric Co. completed a preliminary study to determine whether EHD pumping could be used to help cool transformers in distribution circuits and, if so, to quantify the expected benefits (TPS82-635).

This study used a toroidal-glass-tube, bench-top apparatus so that conditions could be easily changed and flow readily observed (Figure 1). The electrodes were two parallel circular screens separated by about 1 cm, with dc voltages on the order of 20 kV imposed between them. Various electrode screen designs and voltage waveforms were evaluated. Oil velocities as high as 5 cm/s at pressure drops of 5 cm of oil were readily obtained under practical conditions. There is ample evidence that this velocity can be increased by modest changes in screen electrode design. The contractor also built and successfully operated a scaled-up test apparatus that is more closely representative of the application of an EHD pump in a transformer radiator.

Conceptual transformer designs with EHD pumping to augment normal convective cooling were then developed and analyzed. One design is shown in Figure 2. These analyses indicated that even after considering the cost of the EHD pump components, cost savings are possible for transformers larger than 167 kVA. If EHD pumping is added to a conventional transformer, it should reduce oil temperature by about 10°C. Analyses of pump component failure modes and rates were also performed. These were judged to be acceptable, given proper component design and selection.

The next step would be to construct a prototype distribution transformer based on the developed conceptual design and to conduct thermal and dielectric tests to verify that the expected performance can be achieved. This step is currently under consideration. *Project Manager: Joseph W. Porter*

A new generation of capacitors

Capacitors are familiar components used to improve the performance of electric power distribution systems. The capacitors in production today reflect a steady progression of improved designs and materials that have optimized capacitor performance. Thus in size, weight, and cost, a modern 150-kVAR capacitor is quite similar to a 25-kVAR ca-

Figure 1 This bench-top apparatus was used in testing an electrohydrodynamic pump (which is contained in the section of glass tubing in the foreground). EHD pumping is being explored as a means of cooling distribution transformers.

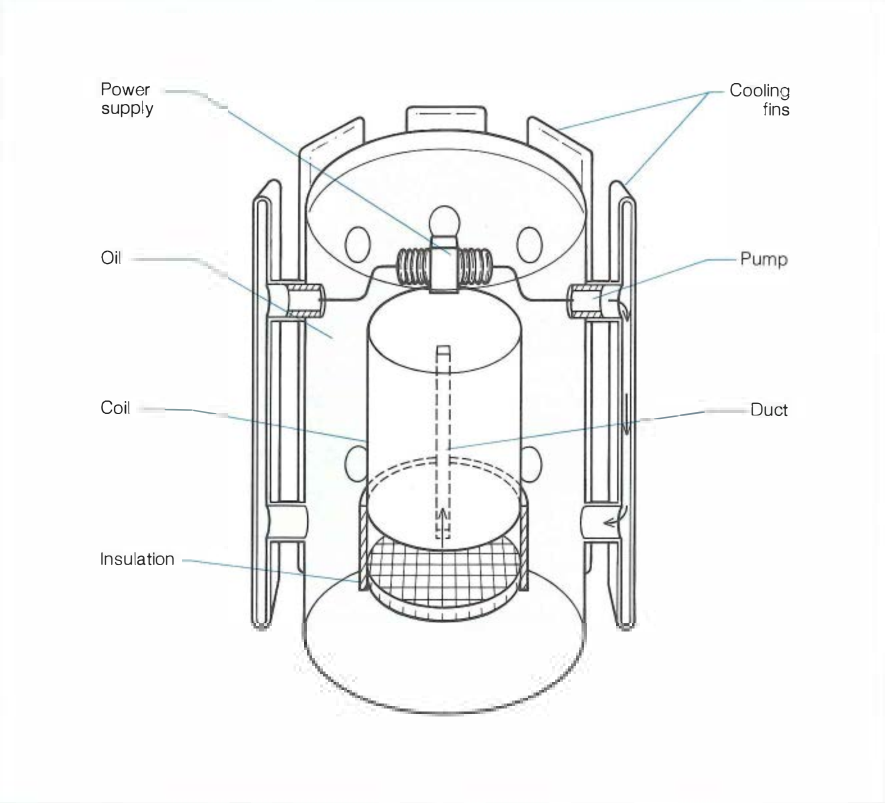


Figure 2 In this conceptual design, an electrohydrodynamic pump is located in each header of a distribution transformer tank. (Alternatively, a pump could be located below the coil.) By applying an electric field, the EHD pumps promote the circulation of the insulating oil through many ducts in the primary and secondary coils and then through the cooling fins.

pacitor built 40 years ago, but its losses are only half as great.

One of the early significant improvements in capacitor design was the switch from mineral oil to askarel as an insulating impregnant. However, the environmental hazards of this substitution, unanticipated at the time, eventually resulted in the need to develop new insulating fluids. In some respects the new fluids are superior to askarel, but in others they are not quite as good.

Although the latest generation of insulating fluids has been tested thoroughly and found to be environmentally compatible, there is still doubt in some minds about their ultimate long-range acceptability. Furthermore, liquids are more easily dispersed than solids, and the spill of a liquid, no matter how benign, still creates a mess that must be cleaned up. As a result, EPRI has undertaken a project to develop a liquid-free capacitor technology and to build prototype units that are essentially equal to current capacitors in all respects (RP2205).

The contractor, General Electric Co., started work in March 1983 and is now screening various approaches to the construction of dry components. Extensive electrical and physical tests will be conducted to select the most promising techniques for more exhaustive investigation. Ultimately, General Electric will select one design for the construction of laboratory prototype units, which will be thoroughly performance-tested. Then 15 manufacturing prototypes will be produced for field trial in the form of five switchable, pole-mounted banks.

This ambitious program promises to advance the state of the art of capacitor technology by a step that will equal the best of past achievements. The present schedule calls for completion of the manufacturing prototypes by the end of 1985. EPRI hopes that the new design will be commercially available in time to allow some remaining askarel-filled units to be replaced with dry units. *Project Manager: Herbert J. Songster*

Extruded dielectric cable surveys

EPRI is funding two survey projects in the area of extruded dielectrics. RP2439 (University of Connecticut Institute of Materials Science) focuses on materials, and RP2438 (Battelle, Columbus Laboratories) focuses on processing, including extrusion and cross-linking. Each project will evaluate the state of the art in its respective area. (EPRI is also currently sponsoring a project, RP1593, on an improved cable manufacturing process; see the *EPRI Journal*, January/February 1983, p. 43.)

In recent years suppliers and manufacturers have made many efforts to resolve problems related to improved cable life. For example, utilities have received cables composed of tree-retardant polyolefins and cables processed by dry-curing techniques rather than by conventional steam curing. Although such efforts have produced benefits, it is still not clear whether the new materials and methods result in increased cable life.

A key question is whether or not to initiate additional work in these areas; the EPRI surveys are designed to provide this guidance. Each project will last one year, and each contractor will survey organizations worldwide in both the plastic and rubber industries. The results are expected to clarify the need for further research. *Project Manager: Bruce Bernstein*

OVERHEAD TRANSMISSION

Unexplained transmission line outage

A growing number of electric utilities have found that certain 345-kV transmission lines are performing significantly below their design criteria because of unacceptably high outage rates. The number of outages occurring above the design criteria is unexpected. These outages are unacceptable in that they cause relays to open lines and interrupt scheduled transmission, resulting in decreased reliability, loss of revenue, decreased switch life, and increased frequency of transformer, switch, and line maintenance.

In the past utilities have attempted to isolate the causes of unexpected outages in traditional ways (e.g., line patrols, tree inspections, and corona and grounding analysis), often without success. In addition to lightning and system overvoltage—the most likely causes—the utilities investigated such less likely ones as wetted insulators, wind-blown contaminants, and bird droppings. They tried unconventional remedies and overdesign retrofits, including additional insulators, bird guards, and increased air gaps. However, these remedies proved to be only temporary, or they only reduced the outage rate or shifted the outage location.

When engineers at the various affected utilities began to contact each other, they found that their individual research had identified certain common outage patterns. They had all determined that outages occurred in the early morning hours (midnight–8:00 a.m.), in different patterns during different seasons of the year, in open and treeless habitats, and in areas where large birds are frequently sighted.

These independent studies, as well as contacts with other utilities and past scientific research, led some utilities to deduce that either droppings from large birds (e.g., golden eagles, red-tail hawks, turkey vultures) or wetted insulator contamination was the most probable cause of the unexplained outages. The problem was that neither the relative contribution of these two factors nor the most effective engineering design to control them was known.

To combine their knowledge and resources, some utilities—including Sierra Pacific Power Co., Idaho Power Co., Bonneville Power Administration, and Pacific Power & Light Co.—have joined forces and are now working together with EPRI under RP2335 to investigate outages on one transmission line. That line is a 42-mi (67.6-km) section of Sierra Pacific Power's Tracy-Valmy 345-kV line. It was selected by the utilities for several reasons: it has a high outage rate and is easily accessible; fault indicators are located on each tower; the area has high levels of alkali contaminants, as well as sizable populations of large birds; there is a parallel line; and the test line has both V-string and I-string insulator configurations to enable comparisons.

The goals of RP2335 are to identify solutions to the existing unexplained-outage problem and to determine design considerations for future transmission lines in the western United States. The results should provide direction toward cost-effective solutions to outage problems. Also, the knowledge gained will serve as a general guide that will help utilities in other geographic regions, each with its own unique environmental factors, to improve their transmission line designs and operations. *Project Manager: Richard E. Kennon*

Transmission line optimization

Utilities planning to build transmission lines in the 115-kV to 500-kV range can soon use a new computer program to search out and assess the hundreds of design options available. The program will check each design to see if it meets the utility-specified design criteria, then identify the design that provides the lowest cost. The user can specify whether lowest initial cost or lowest lifetime cost is preferred.

The concept of a design optimization program is not new; consultants have offered this service for several years. However, with the development of the TLOP (transmission line optimization) computer program, utilities can now perform these studies in-house (RP2151). The initial version of TLOP covers the six structure types shown in Figure 3. In 1984 wood pole structures will be added to the program.

One very important feature of TLOP is its user-friendly design. Transmission line engineers who attended a recent seminar at Power Technologies, Inc., found that the program could be easily applied to the designs they brought with them. These engineers have installed TLOP on their own computers and are providing feedback before the general release of the program.

The EPRI staff thinks that TLOP could be an indispensable tool—one that every member utility requiring transmission lines should obtain. To aid users EPRI will conduct a series of seminars on TLOP in 1984. After an introduction to the program's theory and design, the seminars will emphasize sample problems to be worked out in class. The schedule is as follows: June 12–14, Schenectady, New York; June 26–28, Fort Worth, Texas; and July 10–12, Palo Alto, California. For additional information or registration, call the EPRI project manager, John Dunlap, at (415) 855-2305.

Although the optimization concept may seem simple, in practice a large number of alternatives must be evaluated, each requiring several complex calculations. For example, a transmission line designer searching for the lowest-cost option that fits his particular constraints will want to look at some 20 or more combinations of conductors and bundles. Each candidate design must be examined to see if it complies with criteria on electric field, radio noise, audible noise, clearances, thermal rating, and the like. Calculations must also address structural and conductor loading, sag and tension, insulation and air gap performance, and structural and foundation cost modeling. After looking at all these design possibilities and computing the cost of each, the designer can select the lowest-cost option.

This is a very laborious task with manual methods, and the optimal design might be overlooked. With TLOP, however, the calculations are easily done by computer. Transmission engineers need no longer dread planning department requests for a long list of "what ifs" because TLOP makes easy work of these estimates. TLOP also checks the sensitivity of the answers to various assumptions, such as those on labor and material costs. In the future this design tool will be expanded to cover additional structure types, both conventional and improved, and upgrades. The initial version of TLOP will be available in mid 1984 for IBM and Prime computers. *Project Manager: John Dunlap*

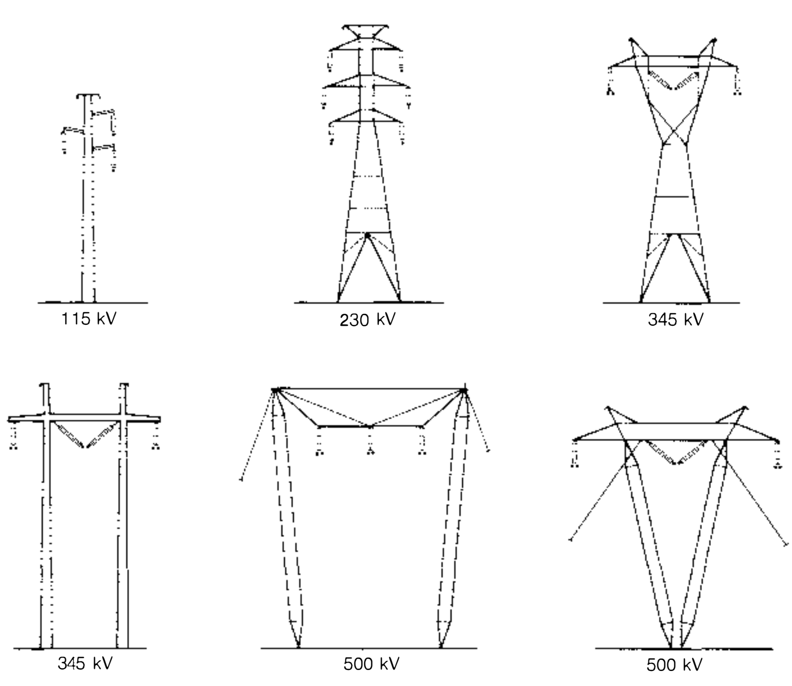


Figure 3 These six structure types can be analyzed with the initial version of TLOP, a transmission line design optimization computer program developed under EPRI contract. Plans call for expanding the program in 1984 to include wood pole structures and other types.

UNDERGROUND TRANSMISSION

Thermomechanical bending effects in pipe-type cables

In the laminar structure of taped cables, the tapes must slide on one another when the cable is bent, and must return to their original position when the cable is straightened. Laboratory and field experience has shown that some designs of EHV pipe-type cable have been unstable under some conditions; that is, the tapes do not return to their original position after repeated cable bending and straightening. Cables with these unstable designs may fail prematurely. Because of the potential risk of costly interruptions in an underground transmission system, EPRI initiated a project with Power Technologies, Inc. (RP7873), to explore this phenomenon, commonly known as thermomechanical bending (TMB).

A significant amount of testing has been conducted thus far; although an additional year's work remains, some tentative but important conclusions can be drawn. The testing has shown that today's cable designs are highly resistant to TMB damage, even when subjected to levels of movement considered implausible in well-designed installations and when cycled substantially in excess of the cable's 40-year life equivalent. The testing has also shown that earlier state-of-the-art designs, while not as resistant to TMB damage, do not develop severe damage except under extreme test conditions.

In addition, the project has resulted in the development of both appropriate test equipment and a procedure for determining whether a given cable design is reliable or not. Another objective, to develop general guidelines for cable construction that would ensure reliability, is being undertaken. Given sufficient testing and proper statistical analysis, researchers should be able to identify both good and bad cable construction features. This in turn should enable them to define and model the critical variables that lead to unstable designs. *Project Manager: John Shimshock*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

ACIDIC DEPOSITION DECISION FRAMEWORK: STATE-LEVEL APPLICATION

Concern over the impacts of acidic deposition has motivated proposals for additional control by state governments of utility sulfur oxide (SO_x) emissions. As a result the ADEPT model, an acidic deposition decision framework developed under RP2156-1 for assessing national legislative proposals, has been adapted to permit cost-benefit evaluation of alternative SO_x control policies at the state level. An illustrative application for Minnesota has been carried out by Decision Focus, Inc., in cooperation with the Minnesota-Wisconsin Power Suppliers Group (MWPSG), who furnished data and data sources for the analysis. The case study, which is reported in EPRI EA-2540, Vol. 3, has demonstrated that ADEPT can be usefully applied at the state level.

As the debate on acid rain has intensified, the need has grown for an integrating framework that can consider not only the uncertain and conflicting information on emission transport, deposition, and effects, but also the cost of emissions control. The bottom line is the need to decide whether additional control should be imposed and, if so, how much and when.

Industry and government are faced with the following options: (1) imposing additional controls on power plants and other potential sources of emissions, (2) taking steps to mitigate the possible effects of acidic deposition, and (3) waiting until a better understanding of the relationship between emissions and ecological effects can be achieved. The choice involves a careful balancing of very different types of risks. Acting now to reduce emissions could lead to large expenditures without concomitant beneficial effects, while waiting could allow significant ecological damage to occur that could have been prevented by prompt action.

If the results of the extensive research programs under way in the United States, Canada, and Europe were available today, the choice might be clearer; unfortunately, crucial uncertainties may not be resolved for 5 to 10 years or longer. Until that time it will be difficult to predict accurately how changes in emissions will affect the extent of ecological damage from acidic deposition. In the absence of perfect foresight, what is needed is a means of reaching the best decision on the basis of information available today. The decision framework developed in Phase 1 of RP2156 offers such a means. The methodologic tools that compose the framework are described in EA-2540, Vols. 1 and 2.

The initial version of the ADEPT framework, developed for regional-level analysis, is currently being used by industry groups and government agencies to evaluate congressional proposals for controlling acidic deposition. As state legislatures consider similar measures to protect sensitive ecological areas within their boundaries, it has become desirable to adapt the framework for use in state-level analyses. Therefore, EPRI had Decision Focus, the contractor for Phase 1 of RP2156, modify the decision framework and then illustrate its application in an assessment of emissions control strategies at the state level.

Minnesota was selected for the trial analysis. Because its legislature recently enacted requirements for acidic deposition standards, it represents an excellent test site. Work on the case study was carried out in close cooperation with MWPSG.

The assumptions and information used in the analysis were drawn as much as possible from public sources, such as the publications of the Minnesota Pollution Control Agency (MPCA). The contractor also interviewed scientific experts identified by MWPSG in order to assemble the necessary input. The critical issues often involved significant uncertainty. One such issue is the relationship between changes in SO_x emissions and changes in acidic deposition in the ecologically sensitive areas of northeastern Minnesota; another involves the probability of, and potential time scale for, significant adverse impacts on aquatic and forest resources in those areas. The contractor and MWPSG attempted to develop data inputs reflecting the best information currently available. However, EPRI views the study primarily as an illustration of how to apply the methodology and does not endorse the values selected. The main accomplishment of the research is its demonstration of how ADEPT can be used in support of state-level decisions.

Two control strategies were examined in the analysis: (1) stricter controls solely on Minnesota utility emission sources, and (2) stricter controls on these sources as part of a regional control program covering the 31 states of the Acid Rain Mitigation Study (ARMS) region and eastern Canada. The level of control used was judged to be essentially equivalent to that specified in federal legislation recently proposed by Senator George Mitchell of Maine.

For Minnesota utility sources, the level of control required by the Mitchell bill was estimated to involve a 26% reduction in sulfur dioxide emissions, which would cost about $30 million annually. In addition to these controls on Minnesota sources, the analysis examined how controls in other states in the ARMS region and in Canada could affect damage from acidic deposition in Minnesota. While the Mitchell bill might require an annual cost of $3–$7 billion or more in the ARMS region, the analysis was restricted to a comparison of the cost of control in Minnesota with the benefits in Minnesota of state and regional controls.

The assumptions and information used in relating emissions to acidic deposition were based on MPCA publications and the judgments of a well-known expert in atmospheric science. The modeling studies cited by MPCA indicate that only a small fraction of

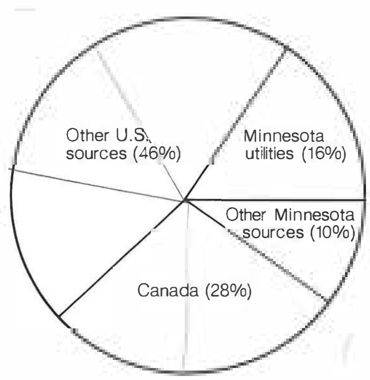


Figure 1 According to this estimate of the sources of sulfur deposition in the Boundary Waters Canoe Area of northeastern Minnesota, a large percentage of the deposition is attributable to emissions occurring outside that state. Minnesota was featured in a case study illustrating the use of ADEPT, an acidic deposition decision framework.

acidic deposition in the sensitive Boundary Waters Canoe Area of northeastern Minnesota results from Minnesota utility sulfur emissions; nearly three-quarters of the deposition results from emissions in other states and Canada (Figure 1). Considerable uncertainty remains regarding the relationship between emissions and deposition. Because of this uncertainty, regional controls based on the Mitchell bill could lead to deposition reductions in the Boundary Waters Canoe Area ranging from only a few percent to over 50%; the most likely estimate is about 20%. In contrast, controls on Minnesota utilities alone are likely to yield deposition reductions of only a few percent.

Estimates of the extent of forest, peat land, and surface water acreage potentially susceptible to acidification were based on detailed inventories compiled by MPCA and other state agencies. A dollar value per damaged acre was then assessed on the basis of economic and other factors.

Judgments about the ecological effects of acidic deposition were based on a review of published studies, interviews with University of Minnesota scientists conducting soil studies, and interviews with experts on aquatic chemistry and fisheries from Minnesota utilities. For the purposes of illustration, five scenarios outlining the extent and time scale of ecological damage were included in the analysis.

While no damage to fisheries or forests has yet been observed in Minnesota, the illustrative base case assumed significant future aquatic damage to have a likelihood of one chance in three, and significant future forest damage to have a likelihood of one chance in ten. If future damage did occur, the chances were assessed as four out of five that this damage would occur slowly, on a time scale of one to several centuries. The small probability of rapidly occurring ecological damage is the major risk associated with waiting for research to resolve uncertainty rather than immediately adopting controls. If irreversible ecological damage is occurring rapidly, then waiting for research could lead to extensive additional damage that could have been avoided by prompt controls.

The results of the cost-benefit evaluation for the Minnesota-only control alternative showed expected benefits of less than $1 million annually, compared with the control cost of $30 million. Since only a small fraction of deposition in the sensitive areas is due to emissions from Minnesota utilities, controls on these sources are relatively ineffective in reducing deposition and hence damage. For the regional control alternative represented by the Mitchell bill, the expected benefits in Minnesota were calculated to be about $8 million annually, again compared with control costs in Minnesota of $30 million.

The choice facing regulatory decision makers is whether to require controls now or to wait. If the results from extensive ecological research now under way indicate that significant ecological damage is occurring, controls could be implemented at a later time. However, imposing controls later might allow some irreversible damage to occur.

The illustrative analysis indicates that waiting leads to a lower total cost (i.e., the combined cost of expected damage and of control) in Minnesota than immediate imposition of a regional control program like that entailed by the Mitchell bill (Figure 2). A sensi-

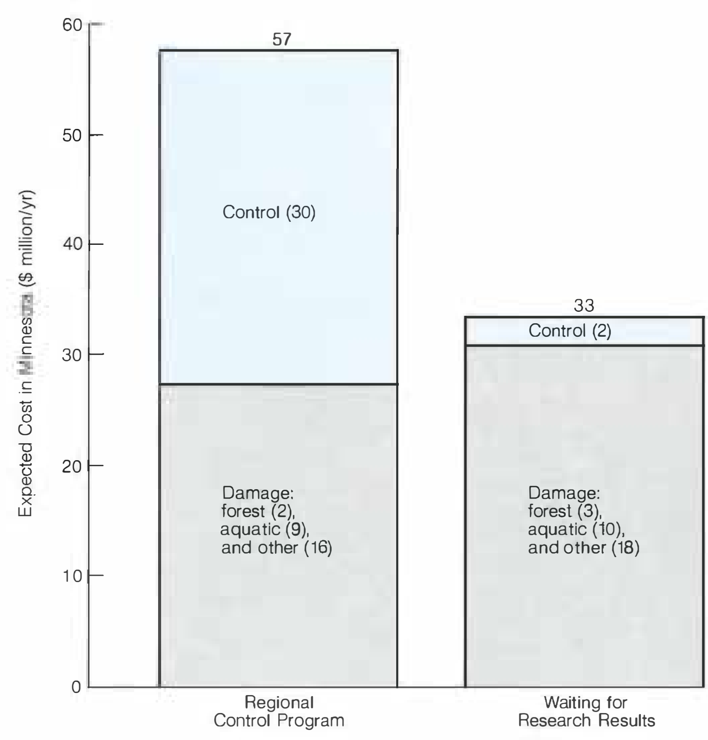


Figure 2 The total annual costs in Minnesota of emissions control and expected deposition damage are compared for two scenarios: (1) immediate imposition of a regional control program as defined in the Mitchell bill, and (2) waiting until various uncertainties are resolved by research and then making the best decision. The expected control cost in the second scenario ($2 million) is calculated as the $30 million control cost times a probability of about 7% that research will show controls to be necessary.

tivity analysis indicates waiting to be the lowest-cost alternative unless the probability of rapid aquatic damage, the extent of sensitive areas, and the value per damaged acre increase by factors whose product is at least 20.

This research under RP2156-1 indicates that the ADEPT model could be adapted for the study of control alternatives affecting Minnesota. The analysis represents a start toward integrating judgments about the costs, benefits, and uncertainties of SO_x emissions control designed to reduce damage from acidic deposition in Minnesota. The research has not demonstrated that the assumptions and data used in the analysis are appropriate as a basis for public policy, although the project team judged these inputs to be reasonable on the basis of its review of the available information. The results from using these inputs with ADEPT indicate that the costs of control in Minnesota outweigh the expected benefits. The alternative providing the lowest total control and damage cost is to conduct a research program to reduce critical scientific uncertainties before deciding on the appropriate level of control.

The ADEPT model is available through the Electric Power Software Center and the EPRI TEAM–UP Software Library. A version is also available for the IBM PC through the TEAM–UP project office. *Project Managers: Dennis Fromholzer and Richard Richels*

SOLID-WASTE ENVIRONMENTAL STUDIES

A major environmental concern associated with the land disposal of solid residues is the release and migration of solutes to groundwater. Protecting groundwater from contamination is the principal basis for regulations being developed under the Resource Conservation and Recovery Act, the Toxic Substances Control Act, and other laws. Requirements that affect waste disposal are of concern to the electric utility industry because it generates over 70 million tons of solid wastes annually. Reliable predictions of the mobilization and environmental fate of leachates are needed to decide when and to what extent control technologies should be applied. Actions not based on strong scientific data could result in controls that are either more stringent than necessary or less stringent than required for safe disposal; in either case costs could increase for the utility industry. To address the need for methods to determine if and how groundwater quality is affected by the disposal of solid residues from fossil fuel combustion, in 1982 EPRI initiated a series of solid-waste environmental studies (SWES).

Near-term activities under SWES (four to six years) include parallel research efforts in geochemistry, geohydrology, and leaching chemistry, as well as evaluations of computer models and field measurement methods. Over the longer term (six to eight years), researchers will develop or improve geohydrochemical models and validate them with field data. Work is under way on six research contracts directed toward the following near-term goals.

- To evaluate existing geohydrochemical models and assemble a usable interim model
- To develop data on the chemical attenuation of inorganic constituents released from the land disposal of solid residues
- To develop data on the leaching chemistry of solid residues
- To develop data on the dispersion and transport of solutes by groundwater
- To evaluate the performance of existing groundwater sampling methods and develop new methods as necessary

The research on geohydrochemical models is divided into three phases. Phase 1 consists of an evaluation of several computer models of geochemical, geohydrologic, and microbiologic processes. Phase 2 will in-

Table 1
COMPUTER CODES EVALUATED

Code	Developer
Unsaturated flow and transport	
SESOIL	Arthur D. Little, Inc.
NRC–SLB	Nuclear Regulatory Commission
OR–NATURE	Oregon State University
UNSAT1D	Battelle, Pacific Northwest Laboratories
FEMWATER/FEMWASTE	Oak Ridge National Laboratory
TRUST/MLTRAN	Department of Energy
SATURN	Geotrans, Inc.
Saturated flow and transport	
PATHS	Battelle, Pacific Northwest Laboratories
SWIP2/SWENT	U.S. Geological Survey
TRANS	Illinois State Water Survey
VTT	Battelle, Pacific Northwest Laboratories
FE3DGW	Department of Energy
USGS MOC	U.S. Geological Survey
AT123D	Oak Ridge National Laboratory
Equilibrium geochemistry	
GEOCHEM	University of California at Riverside
MINTEQ	Battelle, Pacific Northwest Laboratories
PHREEQE	U.S. Geological Survey
EQUILIB	Battelle, Pacific Northwest Laboratories
EQ3/EQ6	U.S. Geological Survey
Microbiologic conversion	
BIOFILM	Environmental Protection Agency
Hydrology-geochemistry	
FIESTA	University of Notre Dame

volve the assembly of an interim model, to be available to the industry in 1986. In Phase 3 the results from SWES research will be integrated to develop new models, and the models will be validated with field data. This R&D status report focuses on the Phase 1 evaluation effort (RP1619-1, RP2485-2).

RP1619-1, the first SWES contract, was awarded to Battelle, Pacific Northwest Laboratories in March 1982. Battelle's first step was to establish criteria for selecting the computer codes to be evaluated. Then the researchers screened the list of available codes (about 100) and selected a representative subset for application to the analysis of leachate migration. Table 1 presents the 21 codes selected: seven for unsaturated hydrology, seven for saturated hydrology, five for equilibrium geochemistry, one for microbiologic conversion, and one combining hydrologic transport and equilibrium geochemistry. Battelle found no codes that model geohydrochemical processes completely and in an integrated manner.

After the selected computer programs were acquired, they were analyzed to determine the mathematical bases of the processes modeled; the numerical calculation methods used; code assumptions and simplifications; and sensitivities, mass balance, convergence, and relative performance.

Preliminary simulations were conducted to establish whether or not the selected codes were suitable for leachate migration analysis. Then three data sets based on real-world landfill and ponded sites were defined for use as input for code simulations of leachate fate. Although these simulations are not yet completed, the initial results indicate that several codes can simulate water movement in subsurface porous media.

There are two established approaches for modeling hydrologic transport in porous media: the kinematic pathline method and the Fickian dispersive method. The kinematic pathline approach neglects dispersive phenomena entirely and simply assumes the advection of solute at a rate proportional to the mean velocity of the groundwater. Solute concentrations are overestimated by this approach because it does not account for attenuation by diffusion, dispersion, and chemical transformation.

In contrast, the Fickian dispersive approach postulates a diffusion-dominated dispersive regime. This approach would seemingly come closer to simulating the characteristics of observed solute migration patterns. Its predicted peak concentrations could also be expected to be more realistic. However, methods of determining appropriate diffusion and dispersion coefficients are not well defined. Efforts to develop a better understanding of dispersive phenomena have led to stochastic methods of estimating coefficients. This work has revealed the spatial and time dependencies of three coefficients—dependencies that existing computer codes are not designed to accommodate. Although codes using space- and time-dependent dispersion coefficients were not available for the initial SWES code evaluation, the Fickian dispersive approach is undergoing further development and will be included in future SWES research.

Some solute transport codes account for chemical transformation (attenuation) by means of a distribution coefficient or retardation factor. The retardation factor approach yields a diminished speed for attenuated chemical species by assuming an equilibrium between the liquid and solid phases of the species; often a constant of proportionality is used to represent this equilibrium.

The research to date has found several hydrologic and geochemical processes to be important in modeling the fate of inorganic solutes. The hydrologic processes are liquid infiltration, redistribution, and drainage; advection; dispersion and diffusion; evaporation and transpiration; conduction; and consolidation. The geochemical processes are adsorption and desorption, precipitation and dissolution, aqueous speciation, kinetic processes, isomorphic substitution, hydration and ion interaction, and thermodynamic processes. Since the role of microbiologic processes in the migration of inorganic solutes is not yet well understood, these processes are not being covered in the later phases of this research.

The initial model analyses show that five types of numerical solution techniques are used in the codes: finite-difference method, finite-element method, integrated finite-element method, method of characteristics, and discrete-parcel random-walk method. The finite-difference method is the most widely used in groundwater computer codes.

The Phase 1 research to date has found no code that models geohydrochemical processes in a complete, integrated manner. More important, basic data for describing field-scale leaching, chemical attenuation, and water transport are not available. Thus the major objective of ongoing SWES research on leaching chemistry (RP2198-2, RP2485-4), chemical attenuation (RP2198-1, RP2485-3), and groundwater transport (RP2280-1, RP2485-5 and -6) is to produce required data for the development of reliable geohydrochemical models (RP2485-2). *Project Manager: Ishwar P. Murarka*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

INDUSTRIAL ENERGY CONSERVATION AND MANAGEMENT

In late 1979 EPRI initiated a research project to evaluate the industrial energy savings potential of advanced energy conservation and management (EC&M) techniques, and to determine what effect the implementation of these techniques would have on utilities (RP1275-1). In Phase 1 of the program, completed in December 1982, a computer analysis explored the technological and economic potential of two EC&M techniques: advanced heat recovery and thermal energy storage (EPRI EM-2573). The objectives of Phase 2, recently completed, were to enhance and document the computer program used in Phase 1 and to establish a pilot program to help utilities identify and evaluate EC&M opportunities for their industrial customers. The overall goal of the project was to provide procedures, documentation, and a computer program to utilities wishing to establish their own EC&M customer service programs.

EC&M techniques encompass a broad range of process and operational modifications. They may be incorporated separately or in combination in industrial plants to improve energy efficiency. Process modifications include the use of waste heat normally removed via cooling towers, the use of heat pumps to elevate process fluid temperatures, the preheating of fuel or combustion air, the use of contaminated waste streams, process electrification, and the production of electricity by using energy that would otherwise be lost. Operational modifications include changes in electricity demand control strategies, improvements or revisions in production scheduling, the adoption of time-of-use electricity rate schedules, and the use of energy management systems.

This report reviews the work performed in RP1275-1: the computer analysis of process-modification EC&M techniques, the computer program expansion and documentation effort, and the establishment of a pilot program for utilities interested in helping their industrial customers pursue EC&M opportunities.

Analysis of EC&M techniques

Phase 1 of the project explored the technological and economic potential of advanced heat recovery systems and thermal energy storage systems. Advanced heat recovery systems use energy available in a waste stream by transferring it through a heat exchanger to another medium, by raising its temperature level with a heat pump, or by using it to drive a Rankine cycle to produce electricity. Thermal energy storage systems can assist in these operations by accommodating mismatches in time between the collection and the use of waste heat. Such systems store the heat in either its sensible or its latent form, depending on temperature, space, and cost requirements.

Data on the availability, performance, and cost of heat recovery and thermal storage equipment were reviewed and compiled to form a computerized data base. Then an existing computer program was adapted as a screening tool to determine the technical performance and economic potential of retrofit systems in industrial plants. The results indicate that advanced heat recovery systems are potentially applicable to a wide variety of industries and industrial processes, and that although the economics of thermal energy storage systems are very site-specific, such systems can enhance energy savings in many industrial plants.

Computer program development

The computer program used in Phase 1 was refined, extended, and documented in Phase 2 for use by individual utilities in performing evaluations of EC&M opportunities for industrial customers in their service areas. The program can be used to assess the technical and economic benefits of installing various types of energy management equipment, and to evaluate process modifications and operating strategies at specific industrial plants.

The program's equipment data base contains performance and cost specifications for four types of advanced heat recovery equipment: various kinds of heat exchangers, open- and closed-cycle electric-drive heat pumps, Rankine-cycle power generation systems, and absorption cooling systems. In addition, the data base covers nine concepts for sensible heat storage (involving 30 types of storage media) and five concepts for latent heat storage (with 67 possible storage media).

The program requires the user to supply plant and process energy use data that have been collected by an energy audit of the industrial plant under study. The input must identify sources of potentially recoverable energy (e.g., furnace exhaust gases, water or other process fluids, overhead condensers, evaporators, compressors, dryers, contaminated solvents) as well as potential energy uses (e.g., electricity production; space or water heating; heating or chilling of process fluids; preheating of process materials, combustion air, or fuel). Also required are data on plant operating characteristics; the electricity rate schedule (an average ¢/kWh rate or a time-of-use rate schedule); economic groundrules; and up to seven daily energy use schedules, which the program scales to account for seasonal variations.

To size and price EC&M equipment for the industrial plant being assessed, the program employs its built-in equipment data base and the user-supplied input. Performance characteristics and operating costs are then calculated for both the existing system and the proposed EC&M system. Finally, the program carries out a discounted-cash-flow (DCF) economic analysis to determine the after-tax return on investment, life-cycle cost, simple and DCF payback periods, and levelized annual cost for each candidate EC&M system.

Industrial customer service program

The overall goal of RP1275-1 was to assist interested utilities in establishing EC&M industrial customer service programs. To this end the contractor, United Technologies Research Center (UTRC), established a pilot program with the cooperation of eight utilities. Each utility identified industries within its service area interested in participating in the program, as follows.

- Arkansas Power & Light Co.: rice processing, ferrous castings, cement block manufacturing
- Carolina Power & Light Co.: mini-steel-mill, canned foods, textile finishing
- Houston Lighting & Power Co.: chemicals, food/beverage processing
- Illinois Power Co.: corn/soybean processing, wiener/meat product casings
- New York State Electric & Gas Corp.: diesel manufacturing, glass containers, large ferrous castings, special alloy preparation
- Niagara Mohawk Power Corp.: stainless and high-alloy steels, electrical equipment manufacturing
- Northeast Utilities: high-technology manufacturing
- Salt River Project: copper smelting

With the assistance of UTRC personnel, each utility conducted preliminary energy audits at the selected industrial plants to obtain data on their processes and energy requirements. The EC&M computer program was then used to analyze these data to identify appropriate energy management strategies. Table 1 presents representative results from these analyses.

An energy audit at a mini-steel-mill in the Carolina Power & Light Co. service area found the most promising EC&M opportunity to be the utilization of high-temperature (2000–2400°F; 1093–1316°C) waste gases from two electric arc furnaces for melting scrap steel. Currently these gases are collected, cleaned in a baghouse, and exhausted to the atmosphere through fans. To assess the EC&M potential of using this waste heat, data on waste gas temperature and plant electricity requirements were analyzed by the computer program. The results indicated that a Rankine-cycle power system—consisting of a waste heat boiler, a power generator, and a booster fan—would produce 3.6 MW of electricity. Installation of this system, estimated to cost $3.2 million, would yield a DCF return on investment of 35% (a simple payback of 2.3 years). Plant personnel are now considering this EC&M option.

Information on the experience of all the utility participants in the pilot program has been compiled for use by other utilities. This information, along with documentation for both the industrial energy audit procedures and the EC&M computer program, was presented to interested utilities at a two-day workshop held last fall at UTRC.

The EC&M computer program is now available to EPRI member utilities. EPRI will maintain the program and provide technical services and documentation. *Project Manager: S. David Hu*

RESIDENTIAL AND COMMERCIAL HEAT PUMPS

Electric heat pumps are growing in popularity in both space- and water-heating applications in residential and commercial buildings in the United States. At present approximately 50% of new single-family homes are electrically heated. Of these, over half (about 26% of the total) use electric heat pumps. Of those new homes built with central air conditioning, about a third use heat pumps. In nonresidential buildings, heat pumps are also gaining in application. To consumers, heat pumps offer a proven option for clean, reliable, and cost-effective electric space and water heating. To utilities, they offer a means of improving annual load factors. To both, development of higher-efficiency devices with improved load characteristics offers significant opportunity for controlling rising energy costs.

A major objective of EPRI's program in electric energy end-use technologies for the residential and commercial sectors is to develop economic and reliable heat pump equipment and systems. Specific goals include improved seasonal efficiency, improved load

Table 1
SAMPLE EC&M ANALYSIS RESULTS

Utility and Industry	EC&M Technique	Energy Source	Energy Use	Installed Cost	Benefit	DCF Return on Investment
Carolina Power & Light Co.: mini-steel-mill	Rankine-cycle power system	High-temperature waste heat from two arc furnaces	Electricity production	$3,200,000	3.6 MW (e)	35%
Illinois Power Co.: wiener/meat product casings	Electric-drive heat pump	Cooling-tower water	Heating of process water	$206,000	Reduction of plant steam requirement by 5500 lb/h	37%
Niagara Mohawk Power Corp.: stainless/high-alloy steels	Waste heat boiler	High-temperature waste heat from reheat furnace	Production of process steam	$655,000	10,000 lb/h of steam	51%
Niagara Mohawk Power Corp.: stainless/high-alloy steels	High-temperature heat exchanger	High-temperature waste heat from reheat furnace	Preheating of combustion air	$460,000	Reduction of furnace natural gas consumption by 38%	137%

characteristics to utilities, and broader application potential in both new and existing buildings. (EPRI research also addresses the application of industrial heat pumps.) The residential and commercial heat pump subprogram currently includes approximately 25 projects. These fall into three categories: equipment and systems development, component and cycle improvement, and applications monitoring and assessment.

Equipment and systems development

EPRI's effort in this area is directed toward improving the performance and cost-effectiveness of electric heat pumps. Near-term objectives emphasize the improvement of commercially available vapor-compression-cycle air-source heat pumps and units capable of using well water, surface water, and ground heat as sources and sinks. Advanced concepts such as alternative thermodynamic cycles and hydronic heat pumps, are also being investigated.

Current research concentrates on central heat pumps for residential and small commercial buildings with warm air distribution systems. A 4.5-year project undertaken on a cost-sharing basis with Carrier Corp. is a major element of this development effort (RP2033-1). Initial technical and economic feasibility studies are nearing completion.

In this project, Carrier is developing an advanced multipackage central heat pump similar to a triple-split system (indoor heat exchanger, indoor compressor, and outdoor heat exchanger). It is expected that this multipackage concept will lead to the economical design of a family of optimal systems for both northern and southern climates in a variety of configurations. Among concepts being explored are a staged compressor, capacity modulation, integration of water heating, novel refrigerant and cycle variations, and advanced fans and blowers.

This advanced heat pump is expected to offer an electric heating/cooling option competitive with advanced gas-fired systems now being developed. It is targeted to achieve a heating seasonal performance factor (HSPF) of 10.4 Btu/h/W (for climatic Region IV, the industry's standard rating region), which would represent an improvement of about 30% over the best currently available central heat pumps. The cooling cycle objective is to meet or exceed a seasonal energy efficiency ratio (SEER) of 14.0 Btu/h/W—the cooling efficiency of the current top-rated air conditioners—while maintaining humidity control.

Other performance targets include a peak demand reduction of 2 kW, reduced outdoor sound levels, improved defrost features, and improved reliability. Control improvements that would allow set-back and load management have also been targeted for development. These improvements should maintain the cost-competitiveness of electric heat pumps and facilitate a power demand profile more favorable to utilities.

Similar performance improvements for room heat pumps are the goal of additional research now being planned (RP2033-2). Specific targets include a 25% improvement in heating performance and a heating demand reduction of 1 kW/ton, compared with the best currently available technology. In the cooling mode, objectives include reduced demand, coupled with an energy efficiency ratio (EER) of 9.0 or better. To make room heat pump units more attractive to consumers and beneficial to utilities, work is also planned to improve applicability in cold climates, reduce indoor and outdoor noise, and improve load management capabilities.

Component and cycle improvement

An important initiative in EPRI's research to improve heat pump components and cycles is a recent feasibility study performed by the University of Minnesota on adjustable-speed motor drives for compressors to modulate heat pump capacity (RP2033-4). Conventional heat pumps for residential and light commercial applications achieve capacity control by intermittent operation (i.e., by cycling on and off at a frequency necessary to approximately match loads). At part-load conditions, the most frequent mode of operation, this on/off cycling degrades efficiency and may decrease comfort levels—particularly in the cooling mode, where humidity control is a concern.

The alternative capacity modulation techniques that were investigated in RP2033-4 use inverter-controlled adjustable-speed drives, which allow continuous or near-continuous heat pump operation. Varying compressor speed in this manner to respond to changes in building heating and cooling loads can improve performance and user comfort, decrease equipment wear, reduce starting transients (starting currents), and lower system operating costs. Higher first costs for controls and motors partially offset these benefits, however. Six advanced ac motor concepts were investigated. The most attractive drives were found to be pulse-width-modulated and square-wave voltage-source inverters, both of which are currently estimated to cost approximately \$200–\$300 per ton of compressor capacity. This suggests that continuously adjustable heat pumps would show a 4–7-year payback in cooling-dominated locations with relatively high electricity costs. Further research is needed to reduce these costs and electric current harmonics entering utility systems.

Other investigations to improve heat pump components and cycles involve non-vapor-compression cycles and nonazeotropic mixture refrigerants, as well as work to perfect system controls, heat exchangers, and compressors.

Applications monitoring and assessment

EPRI is sponsoring applications research to support the development of heat pump technology and to provide utilities with information on heat pump performance and application. Objectives include evaluating the performance of heat pump systems, developing and validating improved methods of system performance estimation, and field-testing commercially available equipment that incorporates novel technical approaches to performance improvement.

Extensive field monitoring and evaluation is under way on high-efficiency central, room multizone, groundwater, ground-coupled, and solar-assisted heat pumps. In addition, the National Rural Electric Cooperative Association and EPRI are cosponsoring preparation of a manual for utility service representatives on heat pump application.

Long-term field monitoring of unitary air-source heat pumps in both heating and cooling modes is continuing (RP2033-9). At present, 14 central and room air-source heat pumps in a variety of climatic conditions are being studied. These include central systems with supplemental electric heat and add-ons to gas and oil furnaces; hydronic add-ons to oil-fired boilers; triple-split systems in combination with single- and dual-speed compressors and with dual compressors; and systems with a desuperheater water heater. The room heat pumps monitored include three units in the Northeast and packaged terminal units in the Midwest and South. The purpose of this monitoring is to collect, analyze, and report the field performance of these air-source heat pumps. Key parameters include heating and cooling energy delivered; energy consumed; operating times; and other data on daily, monthly, and seasonal bases. Peak power demand characteristics, as well as the relative effects of equipment sizing and local climate, are also addressed.

This work extends the field-monitoring efforts of RP789-1 and RP789-3, two prior projects sponsored by EPRI and conducted by Carrier Corp. RP789-1 was undertaken in conjunction with Niagara Mohawk Power Corp. It focused on equipment designed in the mid 1960s and installed in northern climates. RP789-3 and RP2033-9 extended this work into other climates and addressed improved equipment.

In RP789-3, measured HSPFs ranged from 5.6 to 7.4, and cooling SEERs ranged from 7.2 to 9.6. Power demands of these systems were 1.8–8.5 kW below those of central electric furnaces. As expected, the greatest reductions were found with add-on heat pumps. This performance agreed reasonably well with performance ratings based on industry standards (ARI 240-81).

EPRI is also involved in monitoring multizone air-source heat pump systems. Two multizone units have been monitored in residences located in Reno, Nevada, since January 1981 (RP1201-15). Each uses a single outdoor compressor and heat exchanger serving five separate indoor heat exchangers; the indoor units are individually controlled to enable temperature control on a room-by-room or a zone-by-zone basis. Unoccupied areas may be turned off separately or heated to reduced temperatures. Although incomplete, initial data analysis for the two multizone homes shows a significant reduction in peak demand that is attributable to the zone control. Annual energy use is similarly reduced. Further testing of zone systems is being planned.

Water-source heat pumps are also being monitored. Two water-to-air heat pumps have been retrofitted on oil- and coal-fired furnaces in rural Pennsylvania (RP1201-14). One site uses water reinjection into a second well; the other uses surface water disposal. Monthly heating coefficients of performance have ranged from 2.2 to 3.0 for the very cold winter monitored. Further data analysis is under way.

In other research, a solar-assisted ground-coupled heat pump and an unassisted ground-coupled heat pump have been installed in identical residences in Oklahoma, and their performance has been compared with that of an air-source heat pump installed in an adjacent third residence (RP1191-6). The unassisted ground-coupled system saved approximately 28% of the actual yearly energy use over the air-source system. When adjusted for load differences, normalized savings of 25% were estimated.

Heat pump outlook

The future of electric heat pumps is highly promising, and their use in both current and new applications is expected to increase significantly. Key factors influencing this projection are advances in heat pump technology, construction trends, and projected changes in the relative prices of gas and electricity.

In response to market influences (including utility incentives, building regulations, and competitive interest rates), manufacturers are developing improved heat pumps. EPRI's role is to accelerate development of the most energy-efficient designs, to ensure that utility concerns are addressed, and to provide the data needed by utilities in their planning and in assisting customers.

In the residential market, construction price escalation will increase demand for smaller, less-expensive houses. When this is coupled with increases in energy costs, a growing trend toward electric heating by efficient heat pumps should be expected. Increased thermal integrity in homes (e.g., better insulation) should result in lower heating capacity requirements. Further use of common walls in town houses and of common ceilings/floors in low- and high-rise buildings should have the same effect on a per unit basis. These trends are all favorable to increased use of electric heat pumps. The use of submetering and the emergence of suitable room and hydronic heat pumps should also increase heat pump use in multifamily residences.

In commercial construction, low first costs and inherent flexibilities in building reconfiguration are likely to result in broader use of efficient water-loop and packaged terminal heat pumps. *Project Manager: James M. Calm*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

MAIN COOLANT PUMP SEAL RELIABILITY

Main coolant pump (MCP) seal problems in nuclear reactors have had a significant impact on both plant availability and capacity factor. Failures in MCP shaft seal assemblies can lead to the loss of thousands of gallons of primary coolant and to the subsequent loss of hundreds of hours of operation while the plant is shut down for repair. In 1980–1982 MCP seal problems resulted in average plant losses of 0.78% in capacity factor and 0.68% in availability factor for PWRs; the corresponding figures for BWRs are 0.69% and 0.63%. As a cause of lost plant output, MCP seal problems rank eleventh, behind such notable problem areas as steam generators and turbine rotors and blades. During the past five years EPRI has sponsored several projects to help understand and eradicate the causes of MCP seal failure.

PWRs have two to four primary coolant pumps, and BWRs have two to five coolant recirculation pumps. These MCPs operate vertically. They are driven by an electric motor mounted above the pump casing; the motor shaft is rigidly coupled to the pump shaft below. The impeller of these centrifugal pumps is located at the lower end of the pump shaft.

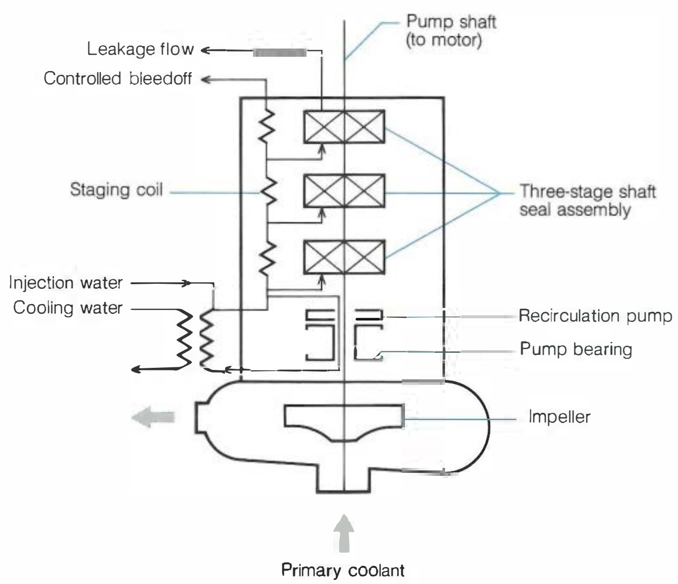


Figure 1 A typical main coolant pump with three stages of sealing and a water injection system for pressure staging, cooling, and proper seal operation. Not all pumps have an independent seal water supply like the one shown here. Injectionless systems instead use primary coolant that leaks through the pump bearing.

Figure 1 shows an MCP with a three-stage shaft seal assembly. This is typical of a PWR installation, where the 2150-psi (14.8-MPa) primary coolant pressure is distributed as 700-psi (4.8-MPa) differentials across the three stages; BWR pumps typically have two sealing stages, with a 550-psi (3.8-MPa) pressure differential across each stage. Table 1 presents MCP component and operating data. Greater design and operating detail can be found in EPRI reports NP-1194 and NP-2458.

Each sealing stage of the pump shown in Figure 1 has a rotating element (usually made of a metal carbide) moving with the pump shaft and a stationary component (usually made of carbon). The rotating seal face is lapped to a smoothness of one to two helium light bands. During operation the gap between the rotating and stationary seal faces is maintained by a thin film of coolant—either water that is injected into the seal assembly or (in other designs) primary coolant that leaks from the system. The viscous shearing of the fluid in this thin film produces considerable heat. One of the critical concerns in seal design and operation is to ensure proper dissipation of this heat to prevent distortion of the seal faces.

If one of the sealing stages should fail, the remaining stages experience an increased pressure differential. Seals are designed to accept this off-normal condition for only a limited period of time, long enough for shutting down the pump in a normal manner and thus avoiding a possibly catastrophic loss of coolant.

The Nuclear Regulatory Commission has been investigating the possibility of a small-break loss-of-coolant accident due to MCP seal failure in a PWR following a complete loss of seal cooling. Such a loss of seal cooling could result from a station ac power blackout or from a failure in the pump's

Table 1
MCP SYSTEM CHARACTERISTICS

Motor-pump weight	175,000 lb (79,380 kg)
Motor size	6000 hp
Rotational speed	
PWR	1180 rpm
BWR	1650 rpm
Pump flow	
PWR	88,000 gal/min ($5.55\ m^3/s$)
BWR	45,000 gal/min ($2.84\ m^3/s$)
Injection water flow	10 gal/min ($630\ cm^3/s$)
Cooling water flow	20 gal/min ($1260\ cm^3/s$)
Controlled bleedoff	1 gal/min ($63\ cm^3/s$)
Leakage flow	
Hydrostatic seal	2 gal/min ($126\ cm^3/s$)
Hydrodynamic seal	1 gal/h ($1.05\ cm^3/s$)

cooling-water system. This accident scenario is predicated on the primary coolant system's being at full temperature and pressure during the assumed loss of seal cooling. (BWRs are not considered in this scenario because they have a greater water makeup capability and because the recirculation loops, where their pumps are located, contain isolation valves.)

The safety-related aspects of MCP seals are one research focus. The seal system is also being addressed as a critical operational component whose reliability has a marked impact on plant availability. This reliability was the thrust of a project (RP1556) initiated in 1981 with Borg-Warner Corp. (Byron Jackson Pump Division) and the University of Virginia in response to the findings of earlier technical planning studies.

Under RP1556 a field survey of 20 power stations was conducted to update the list of known causes of seal problems. This revealed that a wide range of reliability has been experienced in operating and maintaining shaft seal systems considered identical. The failures were divided into three categories: pump system related, maintenance related, and seal design related (Figure 2). For each category fault trees were constructed to describe how seven or eight events typically lead to the observed failure modes. This analysis did not reveal a predominant event–failure mode relationship; rather, it pointed out that corrective actions in all categories are necessary to

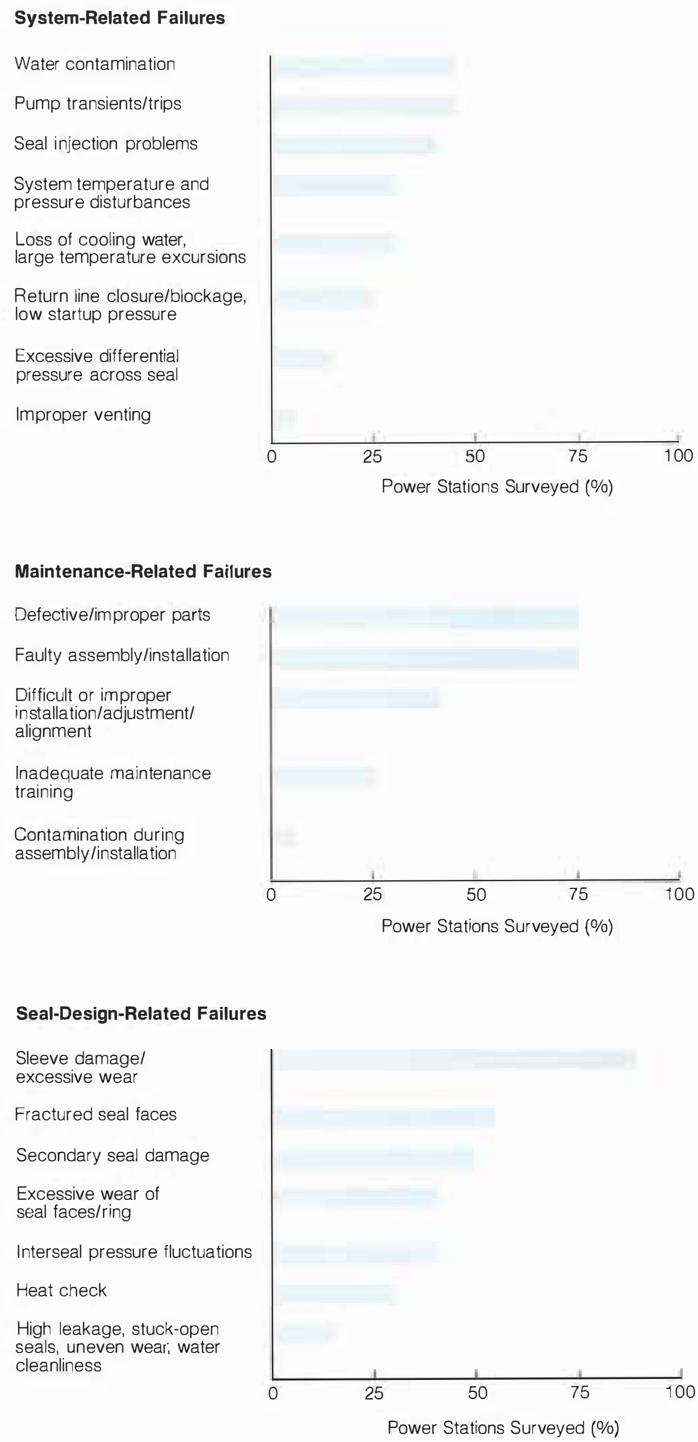


Figure 2 Twenty nuclear power stations were surveyed in 1982 to determine the causes of main coolant pump seal failures. These results indicate the need for improvement in pump system design and operation, maintenance procedures, and seal design.

improve seal and seal auxiliary system reliability. The survey results are presented in NP-2611, Vol. 1.

The next objective of the RP1556 effort was to develop a set of technical guidelines that could be used by the utility, the nuclear steam system supplier, the architect-engineer, and the pump manufacturer together to increase the reliability of both the seal and seal auxiliary systems. The resulting three-volume set of guidelines (NP-2965) formed the basis for discussion at an EPRI-sponsored seminar in May 1983.

These three volumes point to a common factor in seal problems: the lack of an effective communication-response cycle between the pump seal supplier, the system designer, and the operational user. The data indicate that each of these parties has a contribution to make to the total corrective action. The importance of and need for effective communication were endorsed by the seminar attendees, who included 53 utility personnel representing 17 companies.

The technical expertise required for significant improvements in MCP seal reliability is at hand. However, successful mitigation of seal failure will come about only if the parties concerned respond in a spirit of mutual cooperation. Although RP1556 is completed, EPRI is continuing to support research on MCP seals through a contract with an expert on seal design and operation at the Chalk River Nuclear Laboratories. Through activities under this contract, which establishes what EPRI calls a minicenter of excellence, the Institute intends to stay at the leading edge of nuclear MCP seal technology. *Project Manager: Floyd Gelhaus*

CORROSION FATIGUE OF PRESSURE VESSEL STEELS

An inspection during a scheduled refueling outage at Millstone Unit 1 in 1974 identified two badly cracked feedwater spargers. Penetrant tests of the sparger support brackets and of the cladding of the adjacent feedwater nozzle blend radii revealed several cracks in the nozzle cladding. A more extensive examination of the cladding revealed a total of 23 cracks, several of which had penetrated into the nozzle base metal. Subsequently, a number of BWRs that had been operating for more than a year were inspected; all were found to have nozzle blend radius cracks, some of which were deep enough to penetrate into the base metal. In some reactors cracks were also found in the nozzle bore. Although the origin of such cracks is now understood and design changes have been implemented to prevent their occurrence, the problem of BWR feedwater nozzle cracking has focused attention on the need for accurate flaw assessment methods for heavy-section steel components.

Appendix A of Section XI of the ASME Boiler and Pressure Vessel Code presents a procedure for estimating the remaining useful service life of a cracked reactor pressure vessel or nozzle. The procedure combines a fatigue crack growth analysis with a failure margin analysis to determine whether or not a repair is necessary to achieve the desired service life. The fatigue crack growth analysis uses reference curves to calculate the increment of crack growth (Δa) resulting from a transient load that generates a stress intensity factor range (ΔK) at the crack tip. By summing these increments for all expected future transients, an end-of-life flaw size can be calculated for comparison with the maximum allowable flaw size obtained in the failure margin analysis.

Figure 3 shows the reference crack growth curves from Section XI, Appendix A of the ASME code. A single linear curve on double logarithmic coordinates is provided for subsurface flaws. This curve is based on crack growth rate data obtained in air. A bilinear curve, which includes a correction for the influence of stress ratio ($R = K_{min}/K_{max}$), is provided for surface flaws. This is based on data from tests in simulated reactor coolant at 288°C, with a cyclic frequency of 0.017 Hz, ΔK levels of 10 to 60 MPa$\sqrt{m}$, and R ratios of 0.2 to 0.7. In contrast, reactor vessel transients involve ΔK levels from near 0 to >60 MPa$\sqrt{m}$; R ratios ranging from 0 to >0.95; a very wide spectrum of cyclic frequencies; various combinations of water chemistry and temperature conditions; and a number of material compositions and microstructures.

Because several of the variables not accounted for in the ASME code procedure are known to strongly influence crack growth rates in specimen tests, it has been necessary to make the code curves conservative by basing them on the worst behavior seen in the laboratory. As a result, the accuracy of the calculated end-of-life flaw sizes is in doubt. To make more accurate predictions analysts need more extensive laboratory test data, together with a mechanistically based understanding that enables them to extrapolate the data to the component service situation, which involves many combinations of variables not readily reproducible in laboratory tests.

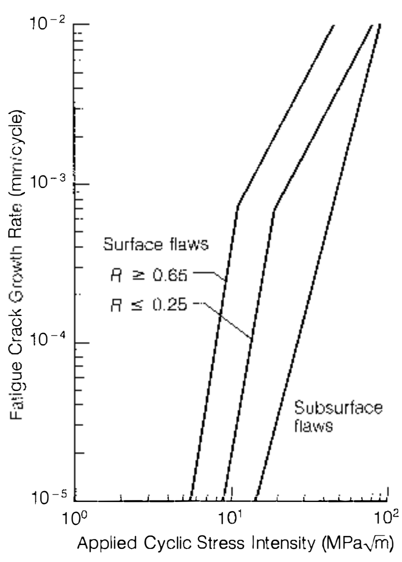


Figure 3 These ASME Boiler and Pressure Vessel Code crack growth rate reference curves can be used to estimate the growth of a reactor vessel flaw during the vessel's remaining service life. The subsurface flaw curve is based on tests in air. The surface flaw curves are based on tests in simulated reactor water and include a correction for stress ratio (R). Linear interpolation is recommended when R is between 0.25 and 0.65.

ICCGR Group

The number of variables that are thought to affect the cyclic crack growth rate in reactor water—and hence that must be addressed in testing—is large. Also, because reactor transients are generally slow, the low-frequency regime is of principal practical interest. Consequently, tests take a very long time—up to six months in many cases. This means that the rate of data generation is slow and the cost is high. Therefore, effective coordination between funding agencies and test laboratories to avoid unnecessary duplication of effort is of paramount importance. Recognizing this need, EPRI and the Nuclear Regulatory Commission took the lead in organizing the International Cyclic Crack Growth Rate (ICCGR) Group, an ad hoc coordinating committee that now has more than 40 members from 11 countries. Group activities have included a data reduction exercise, two testing round robins, and an extensive fractographic study.

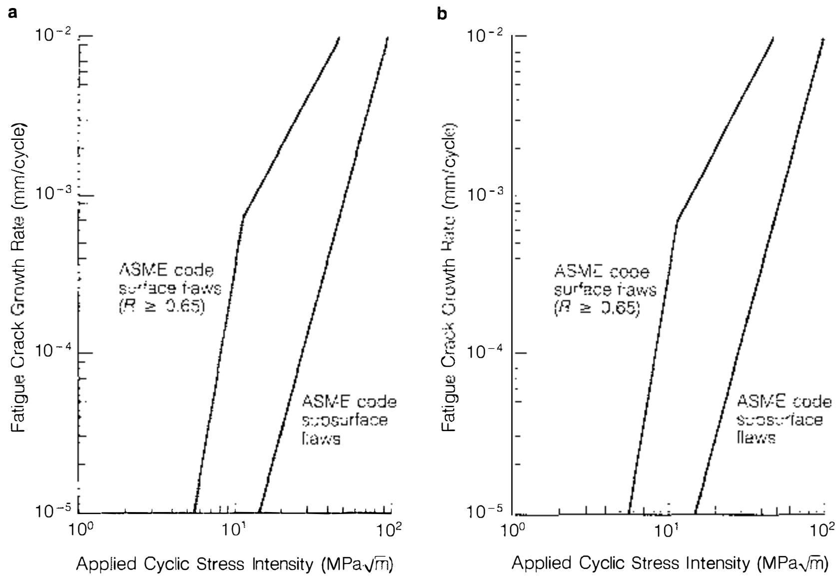
In the data reduction exercise, the 15 active test laboratories of the group's members achieved satisfactory agreement in deriving a curve of crack growth rate in relation to ΔK from a given set of test data on crack length versus cycles. This exercise, together with assessments of the precision of remote methods for determining crack length, has resulted in an agreed-upon procedure for data reduction.

The first testing round robin (for which EPRI provided the specimens through RP1325-5) showed that the laboratories can produce results with an acceptably small degree of interlaboratory scatter if test conditions are specified in enough detail. Among the variables that should be included in test specifications to minimize interlaboratory scatter are waveform and frequency, dissolved-oxygen content, fluid flow rate, the stress ratio (R), and the initial value of ΔK. Another significant finding was that corrosion potential measurements are very useful in characterizing and comparing the electrochemical conditions in different test rigs. Most of the ICCGR test laboratories have now modified their test rigs to accept reference electrodes, which should permit closer agreement in future collaborative efforts.

The current testing round robin is a high-R (0.7) test on 2-in-thick (50-mm) compact tension specimens of A533B steel, which have also been provided by EPRI. Unlike the first round robin, in which the tests were conducted in deoxygenated high-purity water, the high-R tests are being performed in simulated BWR and PWR primary coolants at 288°C, with control tests in air at the same temperature. Only a few tests have been completed to date, but the preliminary results seem to indicate significant differences between the rates of crack growth in the two simulated reactor water environments.

The ICCGR Group has also used fractography to study specimens from the first testing round robin. This examination, supported by EPRI under RP1325-7 and -9, showed that fractographic features differ, depending on whether test conditions produce a crack growth rate like the rate produced in air or whether the crack growth rate is much faster than that in air. In particular, rapid growth rates are associated with the presence of brittle-looking areas on the fracture surface. These areas emanate from manganese sulfide inclusions, which suggests that the sulfides play an important role in crack advance.

Figure 4 Crack growth rate behavior for (**a**) an intermediate-sulfur (0.012%) pressure vessel steel and (**b**) a high-sulfur (0.025%) steel. Data from tests in simulated PWR primary coolant fall in the shaded areas for a wide range of stress ratios and test frequencies. The measured crack growth rates for the first steel (SA508 Cl2) depend only slightly on loading variables. For the second, high-sulfur steel (SA533B-1), measured crack growth rates at a given cyclic stress intensity depend strongly on stress ratio and test frequency.



Recent test observations

At least 15 laboratories are generating cyclic crack growth data for pressure vessel steels in simulated reactor water. Several are now using test systems of the type developed under RP1325-1 (NP-2775), which feature computers for both test control and data acquisition. These systems allow loading variables (e.g., frequency, waveform, and R ratio) to be varied at constant applied ΔK, and their use is helping to clarify the effects of these variables on the cyclic crack growth rate.

Recent test results leave little doubt about the importance of metallurgical variables, which in the past have generally been considered of secondary significance. It is now clear that different pressure vessel steels can exhibit widely different behavior in cyclic crack growth tests in high-temperature water. One extreme is shown in Figure 4a, which summarizes extensive test results for a heat of SA508 Cl2 forging material. The tests, performed by Babcock & Wilcox Co. under RP1325-1, featured simulated PWR primary water and wide ranges of frequency and R ratio, including values of R greater than 0.65. For values of ΔK between 15 and 50 MPa$\sqrt{m}$, no combination of variables increased the steady-state crack growth rate by more than a factor of 5 as compared with the rate measured in air. The figure clearly shows that the pertinent ASME code surface flaw curve predicts crack growth rates that are much faster than those actually exhibited by this steel in laboratory tests.

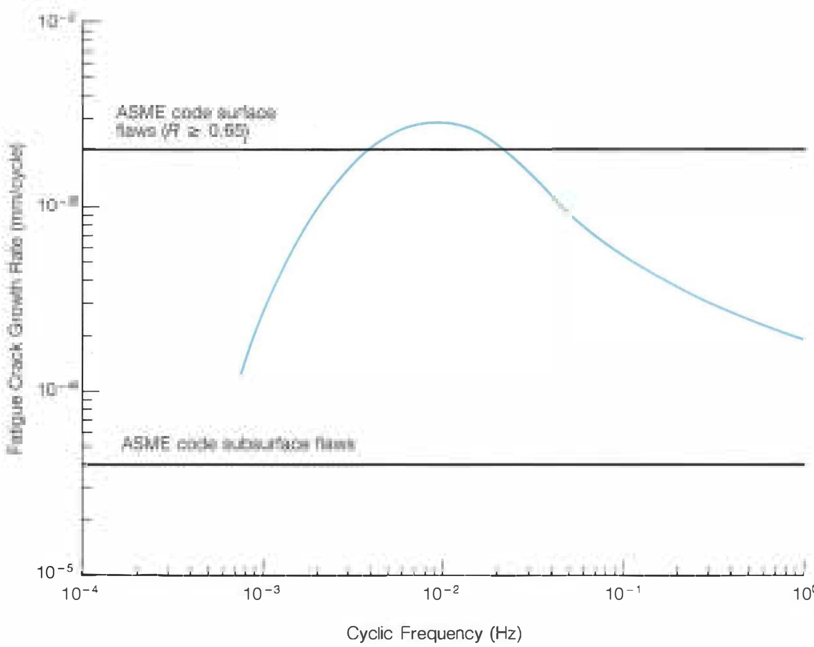
Figure 4b summarizes the results of another test series on a heat of SA533B-1 plate material. In contrast to the results for the forging alloy, the maximum crack growth rates observed for the plate material in PWR water lie close to the pertinent ASME code surface flaw curve and are more than 40 times faster than the rates in air. Similar material-to-material and heat-to-heat variations in crack growth behavior have been reported by several other laboratories.

Although the details are not yet quantified, the available evidence (including that from the fractographic work discussed above) suggests strongly that a steel's sulfur content and distribution are the major metallurgical factors responsible for material-to-material and heat-to-heat variability. Low-sulfur (<0.008%) steels usually show the environmentally insensitive behavior illustrated in Figure 4a, whereas high-sulfur (>0.016%) steels show the more rapid rates of crack growth seen in Figure 4b.

Steels containing intermediate amounts of sulfur (0.008–0.016%) can show either type of behavior—depending, in part, on the sulfide shape and distribution. Large elongated sulfides generally contribute to rapid growth rates, whereas materials containing small spherical sulfides are less environmentally sensitive. (The material in Figure 4a contained 0.012% sulfur in a very fine sulfide distribution.) Specimen orientation and water chemistry also play important roles in determining the behavior of intermediate-sulfur steels.

Loading and environmental variables—such as R ratio, frequency, waveform, and water chemistry—have only small effects on the rate of cyclic crack growth in low-sulfur materials; but for higher-sulfur materials, their effects can be substantial. For example, Figure 5 shows the large effect of frequency on the crack growth rate for a high-sulfur heat of SA533B-1 in tests featuring an R ratio of 0.7 and a sinusoidal waveform. The maximum rate is observed at a frequency of 0.01 Hz, with much slower rates at both lower and higher frequencies. Other tests have shown that sine wave loading leads to the most rapid crack growth rates at a given frequency. The ASME code surface flaw curves were based on tests performed with sine wave loading at a frequency of 0.0167 Hz—test conditions that appear to be close to a worst case in terms of waveform-frequency combinations. Consequently, the ASME curves are expected to overestimate crack growth for most frequencies and waveforms, even for high-sulfur materials. Additional test data are needed to quantify the extent of this overestimation as a function of water chemistry, ΔK, and R ratio.

Figure 5 Effect of test frequency on the crack growth rate at a cyclic stress intensity range of 21 MPa $\sqrt{m}$ for a high-sulfur (0.025%) SA533B-1 steel. The crack growth rate is similar to the ASME code surface flaw prediction only at test frequencies close to 10^{-2} Hz. At other frequencies the measured rates are much slower, suggesting that the code procedure will overestimate the growth of surface flaws in a reactor vessel, where the service loads show a wide range of frequencies.



Another variable requiring more study is fluid flow. A considerable body of crack growth rate data has been obtained under high-flow conditions at the Harwell laboratory of the United Kingdom Atomic Energy Authority. The tests covered a range of materials, including the environmentally sensitive heat of SA533B-1 tested by Babcock & Wilcox under RP1325-1. The Harwell data indicate much slower crack growth rates than those B&W obtained for this material at low flow rates (Figure 4b).

In summary, recent test data suggest that the rates of growth of surface flaws in nuclear pressure vessels fabricated from modern, low-sulfur steels are likely to be much slower than would be expected on the basis of the ASME code flaw evaluation procedure (Section XI, Appendix A), which is based mainly on test data for older, higher-sulfur steels. Code-based predictions will often be very conservative, even for high-sulfur steels, because the surface flaw reference curves represent a nearly worst-case combination of loading variables. The extent of this conservatism is being quantified as a function of environmental and loading variables in continuing work under RP1325. *Project Manager: Robin L. Jones*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP1195-12	Chemistry, Scale, and Performance of a 3-MW (e) Geothermal Plant	4 months	26.5	Hawaiian Electric Co. *J. Jackson*
RP2195-3	Capital Cost and Performance of Alternative Wellhead Power Systems	5 months	109.4	Southern California Edison Co. *E. Hughes*
Coal Combustion Systems				
RP1260-43	Emission Reduction Analysis Model: Coding and Implementation	6 months	286.6	TERA Corp. *M. Miller*
RP1961-5	FGD Parametric Modeling Experimental Design	6 months	71.8	Kilkelly Environmental Associates, Inc. *C. Dene*
RP2422-2	Ash Utilization in Roadways, Embankments, and Backfills (Phase 1)	4 months	165.1	GAI Consultants, Inc. *D. Golden*
Electrical Systems				
RP1499-4	Arc Products in Transformer Systems Containing C_2Cl_4	6 months	57.9	Springborn Laboratories, Inc. *G. Addis*
RP2028-4	Pyrolysis and Combustion of Aroclor 1254–Contaminated Dielectric Fluids	10 months	106.0	New York State Department of Health *G. Addis*
RP2444-1	Development and Validation of Harmonic Power Flow Program	13 months	100.0	Purdue Research Foundation *J. Mitsche*
RP2484-1	Special-Purpose Power System Simulation	17 months	200.0	Purdue Research Foundation *J. Mitsche*
Energy Analysis and Environment				
RP1826-15	Risk Assessment for Electrical Equipment Fires and PCB Spills	2 months	26.0	Resource Planning Corp. *A. Silvers*
RP2359-22	Fuel Procurement Strategies: Issues and Options	7 months	75.0	Arthur Andersen & Co. *H. Mueller*
RP2378-6	Workshop: Evaluation of Monitoring Equipment for Personal Exposure Assessment	7 months	32.0	Harvard University *C. Young*
RP2378-8	Toxicity of PCB Substitutes	2 months	27.3	Systems Applications, Inc. *W. Weyzen*
Energy Management and Utilization				
RP226-8	Thin-Section Graphitic Electrode Substrates for Zinc-Chlorine Cells	9 months	93.7	Great Lakes Research Corp. *D. Douglas*
RP1201-33	Assessment of a Tactical Plan for the Energy Utilization and Conservation Technology Department	6 months	54.0	Energy International, Inc. *T. Schneider*
RP1276-19	Cogeneration System Design and Evaluation	15 months	170.9	Impell Corp. *D. Hu*
RP1677-10	Use of Gas From Solid-Waste Landfills and Wastewater Treatment Digesters in Multimegawatt Fuel Cell Power Plants	6 months	89.5	SCS Engineers *D. Rigney*
RP1745-12	Monitoring for Predictive Maintenance	32 months	629.2	Ontario Hydro *C. Sullivan*
RP2033-14	Crawl Space Earth-Coupled Heat Pump Experiments	9 months	60.0	Union Carbide Corp. *C. Hiller*
RP2034-10	Seminar: Indoor Air Quality	8 months	54.7	W. I. Whiddon & Associates *G. Purcell*
RP2285-6	Lighting Handbook for Utilities	6 months	48.9	Enviro-Management & Research, Inc. *S. Pertusiello*
RP2416-14	Application of Rotary Plasma Arc Furnace to the Abrasive Refractory and Ceramics Industry	6 months	50.0	Applied Technology Laboratories *L. Harry*
Nuclear Power				
RP825-6	Standard Radiation Monitoring Program	9 months	51.9	Combustion Engineering, Inc. *R. Shaw*
RP1585-6	Proposed Action Plan for Future Small LWR Plants	4 months	50.0	MPR Associates, Inc. *K. Stahlkopf*
RP1585-7	Proposed Action Plan for Future Small LWR Plants	3 months	38.0	Ransom & Casazza, Inc. *K. Stahlkopf*
RP2392-15	Benchmarking of the MAAP Code	9 months	150.0	Fauske & Associates, Inc. *J. Carey*
RP2406-3	Heater Testing of Simulated BWR Consolidated Fuel	6 months	27.4	Ridihalgh, Eggers & Associates, Inc. *R. Lambert*
RP2414-1	Radwaste Ion Adsorption Demineralization	11 months	40.6	North Carolina State University *M. Naughton*

New Technical Reports

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

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

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ADVANCED POWER SYSTEMS

Wind Turbine Performance Assessment: Technology Status Report No. 6
AP-3284 Interim Report (RP1996-1); $14.50
Contractor: Arthur D. Little, Inc.
EPRI Project Manager: F. Goodman, Jr.

H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation
AP-3290 Final Report (RP1658-1); $29.50
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: W. Reveal

COAL COMBUSTION SYSTEMS

Acid Deposition on Ductwork
CS-3240 Final Report (RP1871-4); $22.00
Contractor: Burns & McDonnell Engineering Co.
EPRI Project Manager: C. Dene

Action of Fuel Oil Additives Containing Magnesium and Manganese on Superheater and Reheater Surfaces
CS-3281 Final Report (RP1839-1); $11.50
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: J. Dimmer

ELECTRICAL SYSTEMS

Probabilistic Assessment of the Risk of Turn Insulation Breakdown in Large AC Rotating Machinery
EL-3266 Final Report (TPS82-639); $22.00
Contractor: University of Arizona
EPRI Project Manager: D. Sharma

Conductor Fatigue Life Research
EL-3297 Final Report (RP1278); $17.50
Contractor: Auburn University
EPRI Project Manager: J. Porter

Fault and Partial Discharge Location Systems for Gas-Insulated Transmission Lines
EL-3313 Final Report (RP7875-1); $13.00
Contractor: Ontario Hydro
EPRI Project Manager: V. Tahiliani

Designing Algorithms and Assignments for Distributed Processing
EL-3317 Final Report (RP1764-3); $13.00
Contractor: Carnegie-Mellon University
EPRI Project Manager: J. Lamont

Modeling for Power System Simulation
EL-3318 Final Report (RP1714-1);
Vol. 1, $25.00; Vol. 2, $20.50
Contractor: Electrocon International, Inc.
EPRI Project Manager: J. Lamont

ENERGY ANALYSIS AND ENVIRONMENT

Acid Deposition Decision Framework: State-Level Application
EA-2540 Final Report (RP2156-1), Vol. 3; $10.00
Contractor: Decision Focus, Inc.
EPRI Project Managers: D. Fromholzer, R. Richels

Over/Under Capacity Planning Model: Version 2
EA-3149-CCM Computer Code Manual (RP1107); $16.00
Contractor: Decision Focus, Inc.
EPRI Project Manager: H. Chao

Effects of Humidity and Temperature on Conversion of SO_2 to Particulate Sulfate and Sulfite
EA-3310 Final Report (TPS78-770); $16.00
Contractor: John E. Freiberg
EPRI Project Manager: G. Hilst

NUCLEAR POWER

Determination of Tube–Tube Support Interaction Characteristics
NP-3039 Topical Report (RPS174-1); $25.00
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: D. Steininger

PWR Radiation Control: Progress Report No. 1
NP-3280 Interim Report (RP825-1); $28.00
Contractor: Babcock & Wilcox Co.
EPRI Project Manager: R. Shaw

Supply Options and Safety Issues for Hydrogen Use in the Control of Intergranular Stress Corrosion Cracking in BWRs
NP-3282 Final Report (RP1930-6); $11.50
Contractor: SRI International
EPRI Project Manager: A. Roberts

Development of a Honing Tool for Main Steam Isolation Valve Seats
NP-3291 Final Report (RP1939-1); $10.00
Contractor: ESD Corp.
EPRI Project Manager: B. Brooks

Experimental Determination of Effect of Last-Pass Heat Sink Welding on Residual Stress in a Large Stainless Steel Pipe
NP-3361 Final Report (RPT113-7); $14.50
Contractor: Southwest Research Institute
EPRI Project Manager: J. Gilman

Low-Temperature Sensitization of Type-304 Stainless Steel Weld-Heat-Affected Zone
NP-3368 Final Report (RPT110-1); $20.50
Contractor: SRI International
EPRI Project Managers: D. Cubicciotti, M. Fox

Induction Heating Stress Improvement
NP-3375 Final Report (RPT113-1); $32.50
Contractor: General Electric Co.
EPRI Project Manager: A. Giannuzzi

Equipment for Remote Repair of BWR Recirculation-Loop Stainless Steel Piping
NP-3376 Final Report (RPT108-1); Vol. 1, $8.50; Vol. 2, $20.50
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: W. Childs

Effect of Stress-Related Pipe Cracking Remedies on Low-Temperature Sensitization of Welds in Stainless Steel
NP-3379 Final Report (RPT110-3); $14.50
Contractor: Ishikawajima-Harima Heavy Industries Co., Ltd.
EPRI Project Managers: D. Cubicciotti, M. Fox

Effects of Aqueous Impurities on Intergranular Stress Corrosion Cracking of Sensitized Type-304 Stainless Steel
NP-3384 Final Report (RPT115-3); $14.50
Contractor: General Electric Co.
EPRI Project Managers: M. Fox, D. Cubicciotti

Simulations of Hydrogen Mixing Using the Containment Atmosphere Prediction Code
NSAC-59; $11.50
Contractor: Flow Science, Inc.
EPRI Project Managers: B. Sehgal, J. Haugh

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Critical Metals Used by Electric Power Companies: Assessment of Risks and Strategies
RD-3294 Final Report (TPS82-621); $22.00
Contractor: Charles River Associates, Inc.
EPRI Project Manager: R. Jaffee

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