Nuclear Power: The Next Generation

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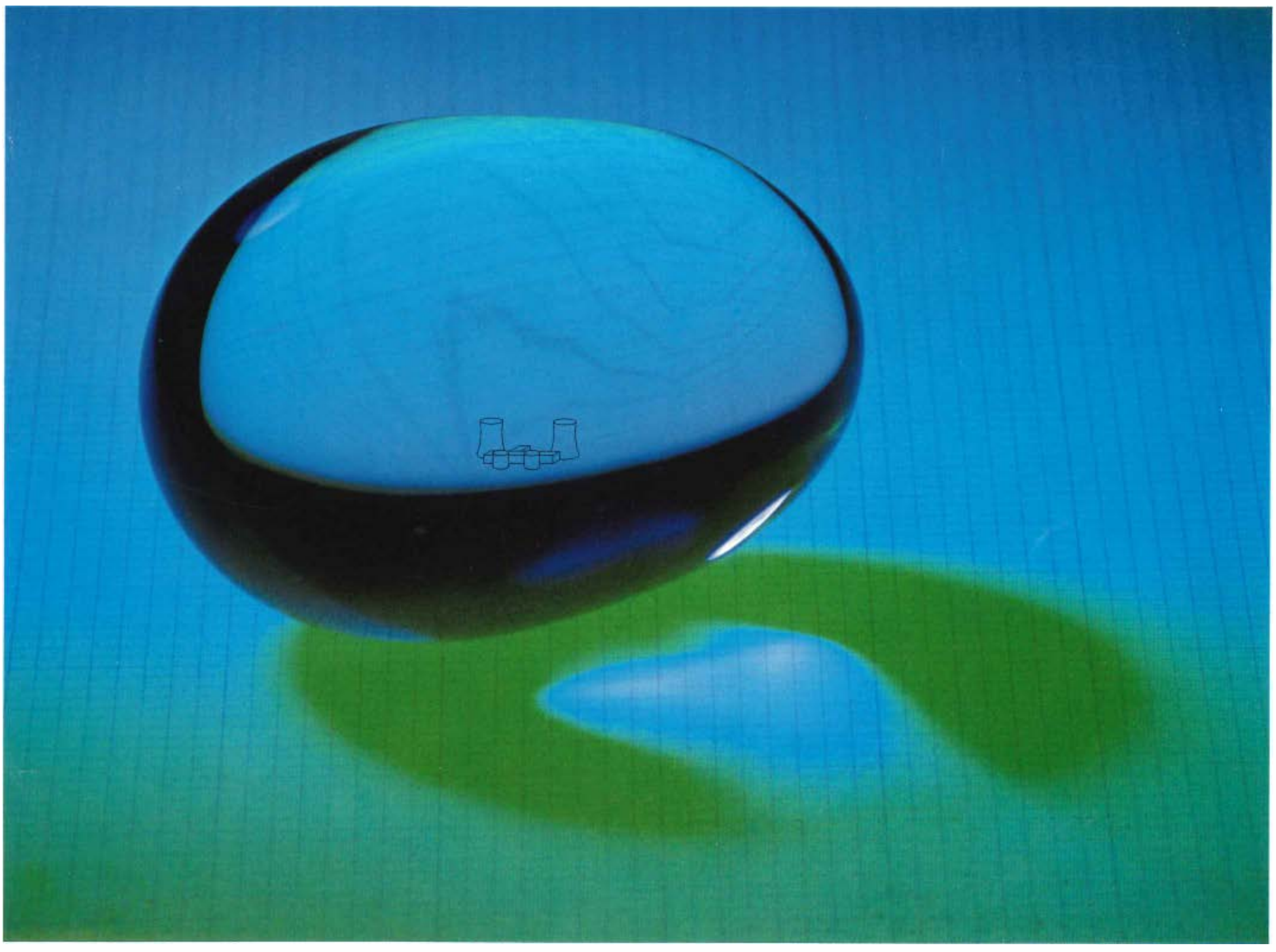

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Cover: A new generation of nuclear plants is taking shape through a nationally coordinated program. The development of an advanced light water reactor—simplified and standardized—is expected within five years.

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Reopening the Nuclear Future

The primary focus of EPRI's nuclear power program is to help preserve the investment of several hundred billion dollars that utilities have already made in nuclear power. In particular, we want to help make sure that this country's nuclear reactors—the workhorses that now produce about 13.5% of U.S. electric power—will continue to operate safely, reliably, and economically for a decade or more longer than their original design life. I believe we are meeting this important goal successfully, but other challenges lie ahead. Even assuming continued low growth rates, active conservation efforts, and new initiatives in peak load leveling, many utilities expect a shortfall to develop in electric generating capacity in the mid 1990s unless ways are found to bring new plants on-line quickly and affordably. To respond flexibly to demand growth when it comes and to cope with inevitable uncertainties in economic circumstances, fuel supplies, and the progress made in research and development, utilities need a variety of options available—conventional and advanced coal-burning plants, systems based on renewable resources, and nuclear power.

Unless we take aggressive action now, however, the nuclear option may not be available to utilities when they need it most. No new nuclear plants have been ordered since 1978, partly because of lower-than-expected demand growth and partly because of the cost overruns and regulatory delays that have plagued the current generation of plants. Reopening the nuclear option will require major institutional change, particularly in regulation and financing, but technical changes are also required.

The question is should these technical changes be evolutionary or revolutionary? Clearly, if another generation of nuclear plants is to be ready for service by the mid 1990s, it must be based on proven light water reactor technology. Nevertheless, utilities have expressed strongly the need to incorporate into the new designs many of the important technical lessons learned from their extensive experience in constructing, licensing, operating, and maintaining the present generation of nuclear plants.

A consensus now seems to be developing among interested utilities that their future nuclear plants will have to be standardized. easier to construct and license, and simpler to operate and maintain. They expect these new plants to prove even more reliable than those already in operation and to incorporate more passive safety features so that investor risk is minimized and an already excellent safety record is further improved.

Utilities also expect that plant design will be optimized so that lower lifetime costs can be achieved. Part of this optimization involves redesign of key reactor components and elimination of some redundant systems. Likewise, incorporating the latest advances in solid-state technology and information processing can help create superior control and instrumentation systems for the new reactors.

For such technically improved plants to be brought into service when they are needed, however, ways must be found to make them less sensitive to licensing uncertainties. This will require an unprecedented cooperative effort among reactor manufacturers, architect-engineers, regulatory agencies, and the utility industry. New plants can be built in a timely manner only when all parties have agreed on the acceptability of their design.

The utility advisory structure has given EPRI the challenge to establish detailed technical requirements for these advanced light water reactors through a program that is described in the lead article of this *Journal* issue. If met, these requirements will ensure that future nuclear power plants will live up to the utility expectations now being expressed. The Nuclear Regulatory Commission's commitment to the review and approval process has already been given informally and the Department of Energy is considering support of the program. If successful, this program could renew public confidence in nuclear power, provide utilities with a vitally important option for meeting future demand needs, and bring credit to all those involved in this unique cooperative effort.

John J. Taylor, Vice President
Nuclear Power Division

Authors and Articles

Countering the familiar technologic trend toward greater complexity, efforts are under way to create a simpler, smaller nuclear power plant, one that can be completed faster than today's designs and then operate more reliably and economically. The whys and wherefores are explained by science writer John Douglas in this month's lead article, **Nuclear Power: The Next Generation** (page 6), developed with the aid of EPRI's Karl Stahlkopf and Warren Bilanin.

Karl Stahlkopf, director of the Systems and Materials Department since June 1980, came to the Nuclear Power Division in November 1973 to manage research in pressure boundary materials and phenomena. He had earlier been in the Navy for seven years, where he specialized in nuclear submarine propulsion and spent a year on the staff of the Chief of Naval Operations.

Warren Bilanin has worked in several special-purpose programs since he came to EPRI as a project manager in October 1979. Now a program manager for advanced LWR research, he continues also as deputy manager of BWR Owners Group research, a post he has held since mid 1983. He was a program manager in the Steam Generator Owners Group program during much of 1982 and 1983. Before that he headed a PWR safety and relief valve test program. Bilanin was formerly with General Electric Co. for seven years.

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Greater complexity still leads to efficiency and economy in some instances. Foundation designs for transmission line poles and towers are a case in point. In **Anchors to the Earth** (page 14), John Douglas traces out the research path toward greater detail and precision in reconciling such design variables as foundation materials, geometry, dimensions, stress patterns, and soil conditions. The article comes largely from the experience of Richard Kennon and Vito Longo, two researchers in EPRI's Electrical Systems Division.

Richard Kennon, manager of the Overhead Transmission Lines Program, came to that post in 1978, having been an EPRI project manager since February 1975. He was previously with Westinghouse Electric Corp. for nearly 23 years, first in sales and marketing, then in engineering, becoming manager of capacitor equipment engineering in 1970.

Vito Longo, project manager, joined the Overhead Transmission Lines Program in January 1984 after four years in transmission line design and special studies for Pacific Gas and Electric Co. Earlier with Power Technologies, Inc., for eight years, he performed analytic and design studies for utility clients in North and South America and conducted research on compact transmission lines for EPRI.

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Chemical treatment is a deliberate routine for continually polishing the purity of the water and steam that circulate through a power plant. But chemical processes can go awry, as revealed in **Chemical Filtration for Steam Purity** (page 19). Two EPRI research managers contributed background information for science writer Francis Kovalcik's article.

Thomas Passell, an EPRI project manager since June 1975, specializes in water chemistry and corrosion control, mostly in nuclear power systems. His background in diagnostic measurements, analytic instrumentation, and radiochemistry comes from 4 years as a staff scientist with Lockheed Missiles and Space Co., 1½ years as a senior physicist with Physics International Co., and 13½ years as a senior physicist with SRI International.

Barry Syrett is a technical adviser with the Materials Support group of EPRI's R&D staff; he specializes in problems of aqueous corrosion, largely in fossil fuel power plants. Formerly with SRI International for nearly seven years, Syrett developed a program of corrosion research there. He also investigated corrosion mechanisms and remedies during earlier work with The International Nickel Co., Inc., and Canada's Department of Energy, Mines, and Resources.

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Mainly a product of utility operations but coming also from research, medicine, and a growing number of high-tech industrial facilities, low-level radioactive waste is fast becoming a high-level problem. The reasons, disposal cost and scarcity of sites, are spurring EPRI-sponsored development of ways to cut waste volume. **The Great State of Uncertainty in Low-Level Waste Disposal** (page 22) details the political context as well as the R&D effort. Taylor

Moore, senior feature writer, wrote the article with the cooperation of Michael Naughton of EPRI's Nuclear Power Division.

Naughton has specialized in radiation control for most of his career, notably as an EPRI project manager since August 1978 and during 13 years with electric utilities. From 1973 to 1978 he was with Boston Edison Co., becoming chief technical engineer at the Pilgrim power plant. From 1965 to 1973 he was with Iowa-Illinois Gas and Electric Co., much of the time on loan to Commonwealth Edison Co. for chemistry and radiation control at the Quad Cities plant.

Stahlkopf

Bilanin

Passell

Kennon

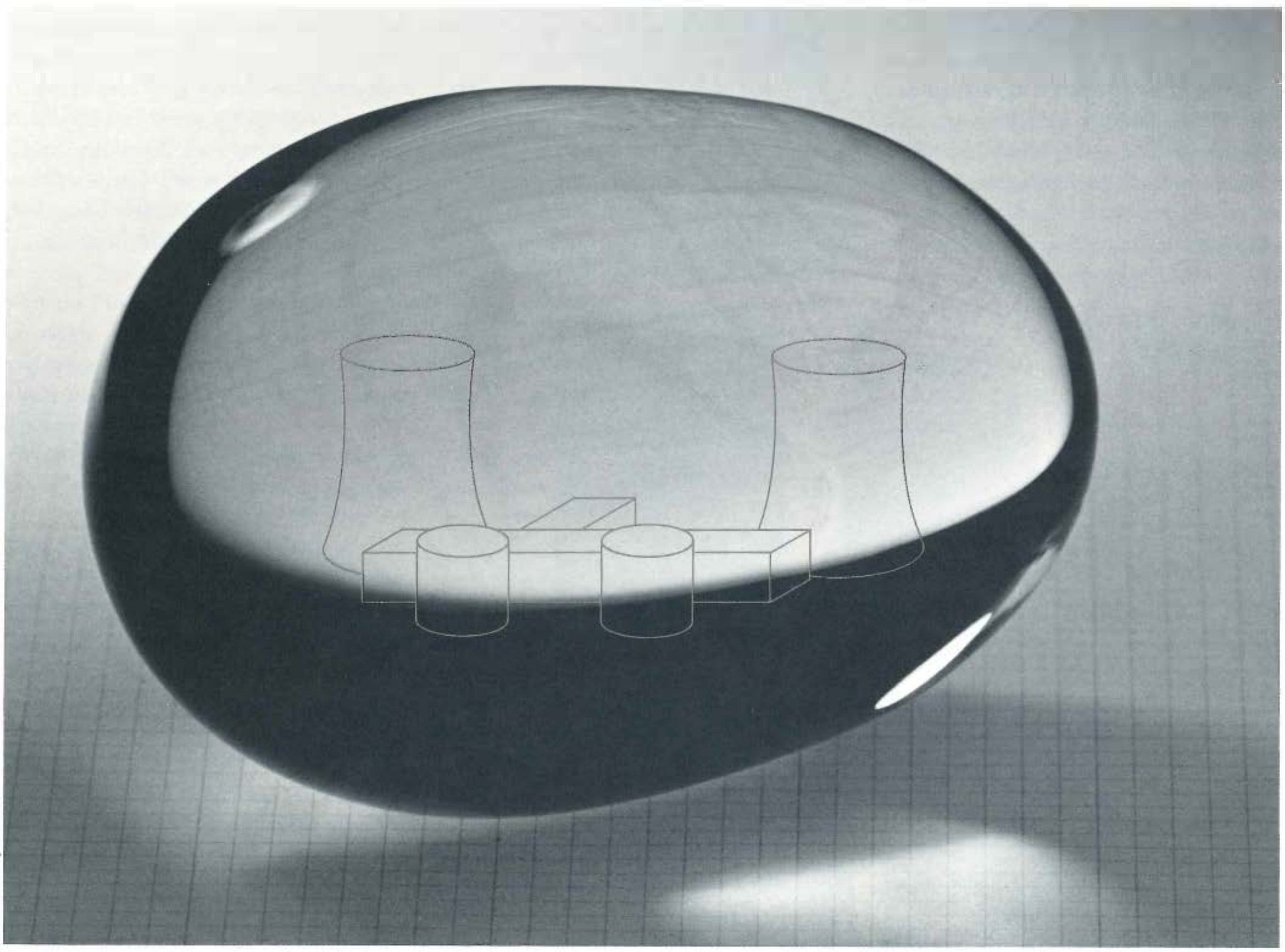
Longo

Syrett

Naughton

NUCLEAR POWER: The Next Generation

A national program is under way to accelerate the evolution of nuclear technology by feeding 25 years of experience into the design of an advanced, simplified light water reactor. The goal is to emerge within five years with the basics of a standardized plant that is safer, lower in cost, and approved by NRC.



Originally, the light water reactor (LWR) was chosen for use in electric power generation because of its potential for having a simple design and for being easily operated and maintained. Although today's commercial nuclear power plants work extremely well, unpredictable regulatory decisions have forced many new components to be added on rather than incorporated into the design. "Treated that way," explains Karl Stahlkopf, director of EPRI's Nuclear Systems and Materials Department, "a nuclear plant can become hung with retrofits that don't necessarily work well together, making reactors more complex but not necessarily safer."

Now a major new program involving cooperative work by electric utilities, EPRI, reactor manufacturers, architect-engineers, and the Nuclear Regulatory Commission (NRC) has been launched to ensure the availability of the nuclear option in the 1990s. The program is based on an emerging consensus that if nuclear power is to remain a viable power generating option for the next decade, when orders for new plants are expected to pick up, an all-out effort must be made now to simplify and standardize plant design. A fresh approach will also be taken to address fundamental institutional issues, such as uncertain licensing requirements and the difficulty of funding new plants. In addition, the program will explore possibilities for building relatively small (400–600 MW) nuclear plants to meet further demand growth after the turn of the century.

This unique, integrated approach to developing a new generation of reactors has come in response to urgent utility requests. Recent surveys conducted by EPRI show that utilities generally want to retain the nuclear option in order not to become solely dependent on coal, and they feel the LWR remains the best near-term candidate for meeting this need. In particular, utilities report that they require detailed specifications for nuclear plants that will offer minimal lifetime cost and assurance of NRC approval.

In response, the five-year, $20 million Advanced Standardized LWR Industry Program has been established in EPRI's Nuclear Power Division. The program will produce a detailed requirements document specifying the design of simplified, standardized LWR plants. Each portion of the requirements document will be reviewed by the Utility Steering Committee and an industry review group consisting of nuclear steam supply system vendors and architect-engineers. These sections will then be passed to NRC for approval. Eventually, utilities can use the document to order a nuclear plant with assurance that it will meet accepted industry standards and all current licensing requirements and that it can be constructed and operated reliably and economically. In addition, conceptual plans for a small nuclear plant will also be produced.

"The current hiatus in nuclear power in the United States is characterized by uncertainties. Our best judgment is that the next generation of nuclear plants must therefore be based on the widest and best experience we have—that is, the light water reactor," comments Solomon Burstein, vice chairman of the board of Wisconsin Electric Power Co. and chairman of the new program's Utility Steering Committee. "Our history, together with the experiences of other nations, tells us that opportunities exist to simplify, modularize, and standardize light water reactor plants."

Path of evolution

Over the years LWRs have become complicated indeed. For example, a typical 1000-MW nuclear plant today contains between 30,000 and 40,000 valves, compared with only about 4000 valves in a commensurate fossil fuel plant. Many of these valves are themselves complex subsystems requiring a motor, position indicator, controls, remote readouts, and other equipment. Elimination of a single, large motorized valve from a plant can save tens of thousands of dollars in capital costs alone, plus further savings in maintenance, inspection, and testing.

A recent review of several pressurized water reactor (PWR) facilities indicated that as many as 40% of their valves could be eliminated by taking advantage of changes in knowledge and functional requirements that have occurred since the systems were originally designed. Even more valves could be eliminated if an integrated approach is taken to simplify the overall design of new plants.

The cumulative effect of such redundancies is staggering. From 1971 to 1982, the per kilowatt requirements of new PWR plants have increased by a factor of 2.75 for cubic feet of concrete, 2.4 for feet of cable, 6.2 for work hours of craft labor, and 7.1 for work hours of nonmanual field and engineering service. Over the same period, total plant costs have roughly quadrupled. Yet one of the strongest indications that room for improvement does exist comes from the fact that similar plants with the same projected date of service may now have estimated costs that differ by a factor of 4.

What can be done? Much publicity has been given recently to proposals that represent a radical departure from the LWR design that has dominated nuclear power generation in the United States for more than two decades. In particular, ASEA–Atom of Sweden has proposed the PIUS (process inherent ultimately safe) reactor that is entirely immersed in a pool of water, which would automatically flood the core in case of a primary system break. Alternatively, proponents of the high-temperature gas-cooled reactor (HTGR) cite its ability to withstand loss of coolant for many hours before core damage occurs. Although both of these designs might eventually offer potential advantages, neither has been built at the 1000-MW scale, and they would thus require construction of a prototype before any commercial orders could be expected.

The delay involved in building and testing a prototype essentially eliminates such novel designs from consideration in the present attempt to create improved reactors ready for order in the 1990s. Further, little or no government support can now be expected for such a prototype. Meanwhile, faced with a diminishing backlog of orders for new plants, the American nuclear industry is slowly winding down its operations. Major suppliers are shifting their emphasis from plant construction to nuclear service contracts, and second-tier suppliers are casting about for new lines of work.

It was against this background that a new, industrywide consensus emerged on the need to continue reactor development along an evolutionary path. On the one hand, if new nuclear plants are to be ordered before the turn of the century, they will have to be based on proven LWR technology, without the need for a prototype and capable of being built by the manufacturing infrastructure already in place. On the other hand, present LWR designs leave room for improvement, especially if an integrated approach is taken to simplify and standardize the plants and to rationalize regulatory requirements.

The program

Several specific characteristics utilities want to see before ordering new nuclear plants were gathered from the recent industry surveys. The broadest requirement is that such plants will have to be able to compete with comparable coal-fired power stations both in cost per kilowatt and in terms of firm schedules for construction and licensing. A target construction cost of $1600/kW has been tentatively adopted, together with a required construction time of 6 years or less. Utilities also want to be able to order plants that will be highly reliable, so tentative design requirements include an average annual availability rate of 80% and an expected lifetime of up to 60 years.

To meet these requirements, design emphasis will have to be placed on minimizing full life-cycle costs, not just on achieving lowest possible initial cost, as in the past. The design will be based on proven LWR technology to take advantage of the experience gained with these systems over the past two decades. Improved features and increased design margins will be provided so that plant operations are simplified and there is more time for the operators to deal with transient and upset conditions, thus keeping minor incidents and operator errors from cascading into major accidents. Provisions will also have to be made at the outset for handling radioactive wastes.

"The guiding philosophy in choosing particular systems," says Stahlkopf, "will be to take advantage of the best off-the-shelf technology." Thus some mechanical systems may be changed very little, while other systems, like instrumentation and control, may take advantage of such state-of-the-art technology as fiber optics.

Already much progress has been made toward ensuring the licensability of nuclear plants designed under the new program. Working with industry representatives, NRC has reduced its list of unresolved safety and licensing issues that will apply to the new plants from 638 to 101, and these, in turn, have been grouped into 34 topics for resolution. In addition, NRC has agreed to review at its own expense the various sections of the program's requirements document for approval. These developments mean that by the time utilities order plants based on the requirements document, each component system will have undergone complete NRC review and approval.

The requirements document will contain 14 system packages, covering such items as safety systems, plant controls, radioactive waste processing, primary coolant systems, and so forth. When designing one of these component systems, a contractor will prepare a package for the requirements document and then submit it to two review groups: one composed of U.S. utility representatives; the other, representatives from nuclear system suppliers and architect-engineers. After approval by these two groups, each package will pass to the Utility Steering Committee for further review and submittal to NRC.

For the small-plant evaluation portion of the program, conceptual designs will be produced for small units of both boiling water reactors (BWRs) and PWRs. If utility interest in small reactors follows, such conceptual designs could be used by nuclear suppliers to produce detailed plans for their own commercial plants, which would also satisfy the requirements document approved by NRC.

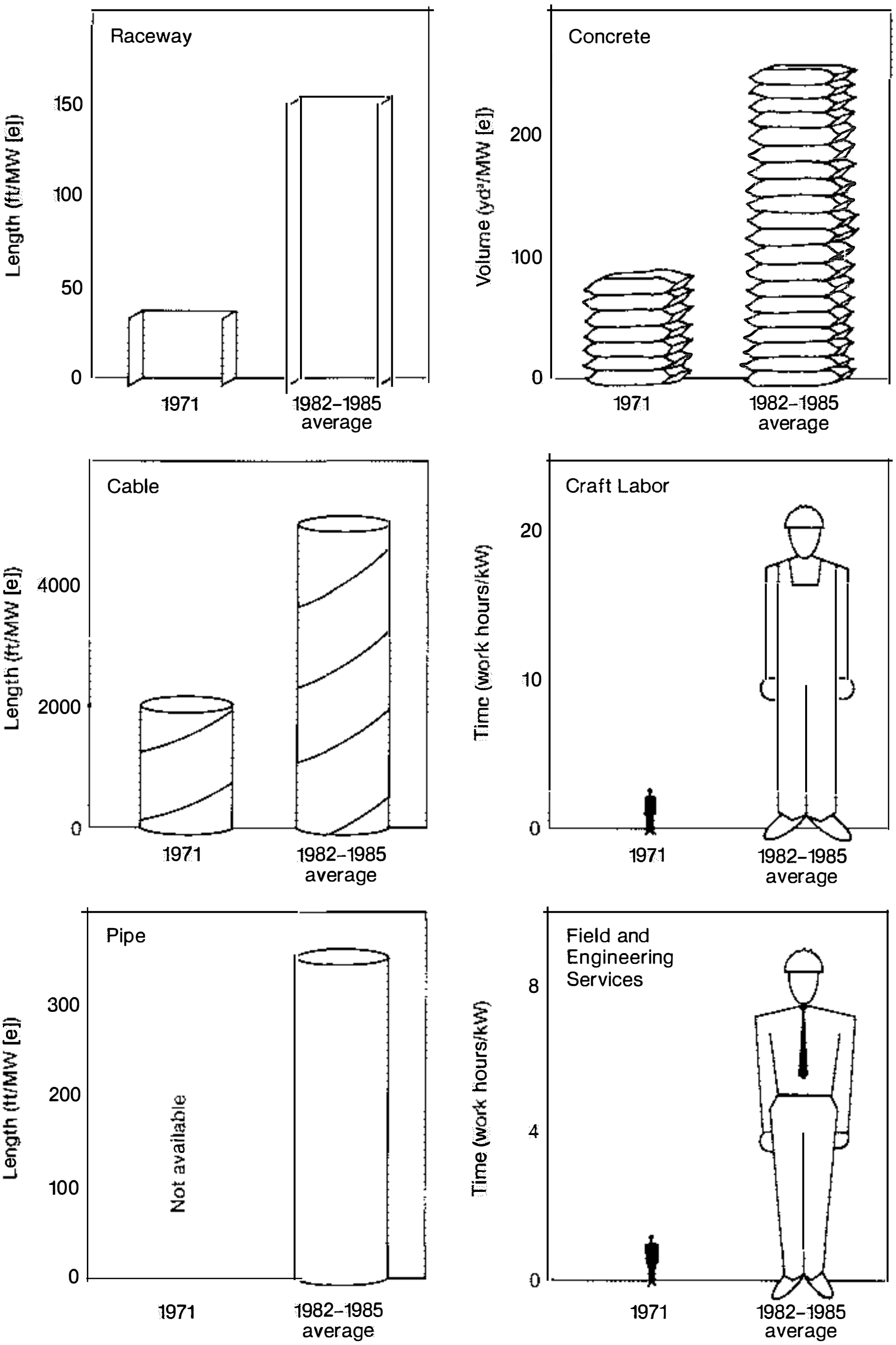
"We believe that utilities should stipulate in detail their requirements for a nuclear plant on the basis of their own extensive construction and operating experience rather than relying primarily on the suppliers," explains John Taylor, EPRI vice president, Nuclear Power Division. "The aim of the current program is to ensure that a balanced set of requirements is available to assure lifetime safety, reliability, and economy. That's why from the beginning we are involving the reactor manufacturers and architect-engineers who have the state-of-the-art design and fabrication technology and are putting them to work directly with utility people who have extensive plant experience."

Optimizing design

Many of the specific steps involved in simplifying and optimizing LWR plants are already well recognized. The requirements document will particularly address the need to eliminate unnecessary plant complexities, reevaluate design margins, and identify ways of making new plants easier to construct, maintain, and operate.

Growth in Material and Labor Requirements

Many individual factors have contributed to rising construction costs of nuclear plants. Since 1971 the amounts of concrete and cable required to build a plant have more than doubled, while requirements for pipe and raceway (trays that hold cables) have more than quadrupled. Similarly, costs of craft labor and nonmanual field and engineering services have increased by a factor of from 6 to 7. By standardizing plant design and shop-fabricating key components, new nuclear plants can be built with sharply reduced requirements for both material and labor.



In some cases, simple configuration changes could be made that would increase plant safety. One example involves preparations for a small-break LOCA in PWRs. In current designs, a small (6-in-diam [15-cm] or less) break in the cold-leg pipe carrying water into the reactor requires automatic actuation of water injection equipment or operator actions to ensure that the water level does not drop below the top of the core. In the unlikely event that such actions are not taken, the core rapidly overheats and can be extensively damaged. This potential problem can be avoided, however, by raising the elevation of various pipes and nozzles in the system so as to maintain water levels above the top of the core, while letting steam escape through the break.

Eliminating needless redundancy is another approach to simplification. An important example of the sort of redundant equipment that might be eliminated by an overall plant redesign is the containment spray system. Of course, detailed studies must be completed to assess whether the removal of this system can be accomplished without compromising plant safety. Originally intended to reduce the spread of radioactive iodine to the atmosphere after a loss-of-coolant accident (LOCA), the containment spray system delivers water containing sodium hydroxide to spray heads near the top of the containment structure. The sodium hydroxide is added to increase the pH of the water and thus enhance its ability to retain elemental iodine, but recent studies have shown that most iodine released during the LOCA is in the form of highly soluble cesium-iodide. As a result of these studies, it now appears that the entire containment spray system would be a candidate for elimination because cesium-iodide could easily be captured by water already in the reactor coolant system or by steam condensing in the containment atmosphere.

Eliminating this one system could

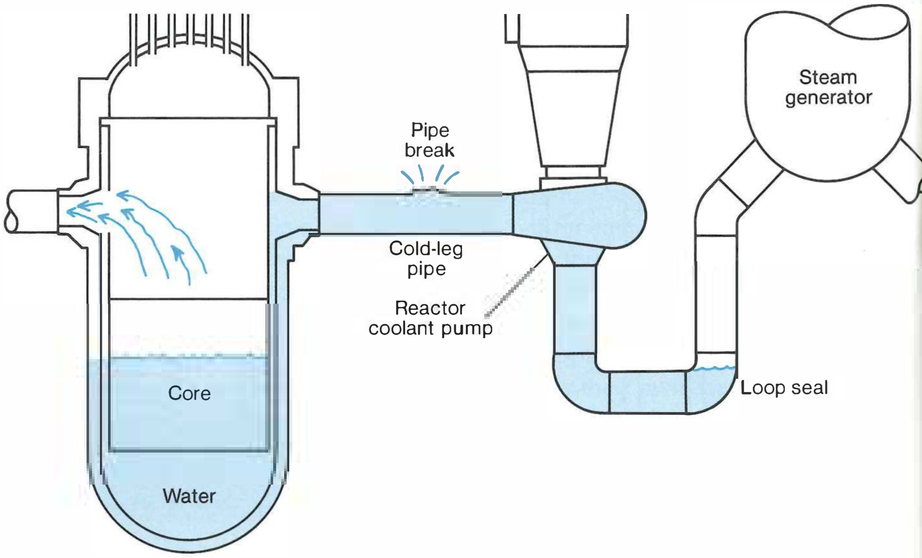
save $8–$10 million in the cost of building a plant, because this system contains about 60 valves, a large tank for water and a small one for sodium hydroxide, and two trains for delivering the mixed solution. By avoiding the possible corrosive effects of sodium hydroxide, plant designers could also consider using aluminum in the containment structure for the first time. In addition, removal of the redundant system would also eliminate a large number of technical specifications and surveillance tests now required.

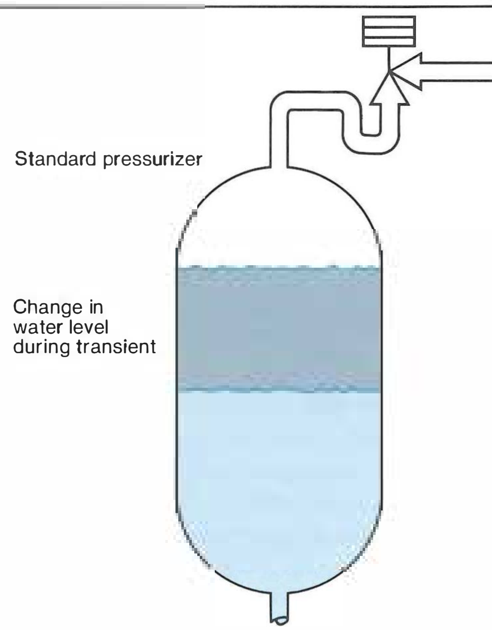
Utilities have also requested that new plants have better response during transients. In response to this request an increase in design margin for the coolant pressurizer in PWRs is being proposed. This unit is essentially a tank containing both water and steam that is inserted along the hot leg of the coolant system to maintain the coolant pressure at a level high enough to prevent boiling in the core. The problem with current pressurizers is that they are not large enough, in themselves, to maintain pressure during transients. When a turbine trips, for example, operators must quickly open power-operated relief valves to limit pressure rise. Conversely, when the power removed from the system temporarily exceeds that being produced in the core, coolant pressure can drop far enough for steam bubbles to form in the reactor vessel despite the presence of the pressurizer.

Both types of problems could be addressed by increasing the size of the pressurizer—perhaps doubling its volume, compared with present models. Although such enlarged pressurizers would cost about 50% more to build, their presence would greatly reduce the chances that a minor transient could get out of hand and cause damage to the primary cooling system. In particular, operators would have more time to react to a transient and less need to use power-operated relief valves. (It was the mechanical malfunction of one such valve, combined with operator

Containing the Small-Break LOCA

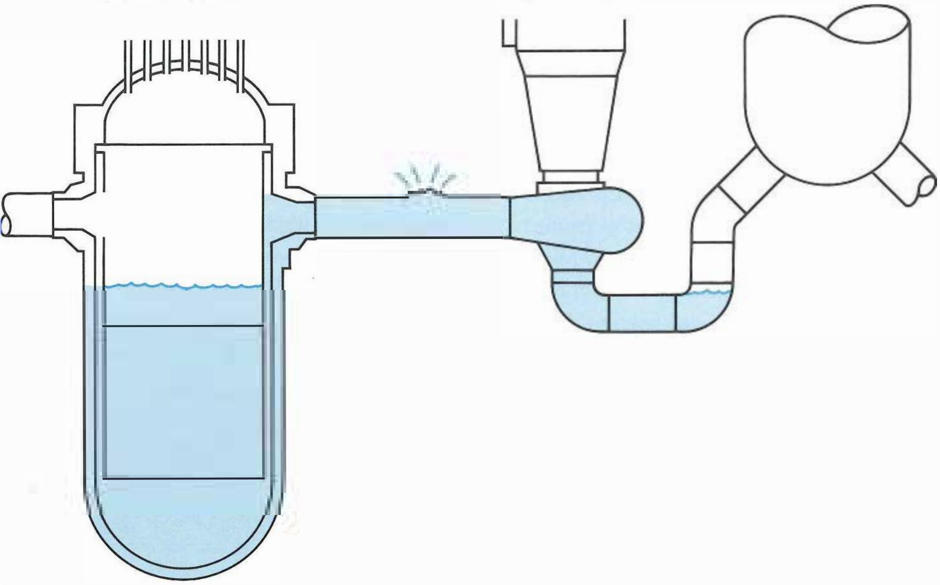
One important design change in new nuclear plants that can help prevent a relatively minor incident from causing expensive core damage involves increasing design margins for small-break loss-of-coolant accidents. When a small break occurs in the cold leg (flow toward the core) of a cooling system, coolant flows out of the break until the water level inside the reactor vessel lowers to that in the loop seal between the steam generator and the reactor



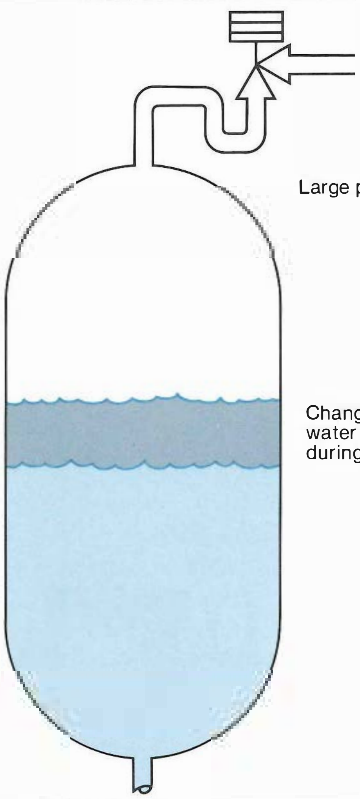


Improved Response to Transients Through Larger Pressurizers

The pressurizer attached to the hot leg (flow away from the core) of a reactor cooling system is designed to keep the system pressure from rising or falling excessively during a transient. Increasing the volume of the pressurizer by as much as 50% in new coolant pump. When the levels equalize, steam escapes through the break and the system depressurizes, allowing the high-flow-rate, low-pressure injection to initiate and ensure core coverage. In today's reactors, unless appropriate actions are taken, the water levels may not equalize until the core is uncovered enough to potentially cause clad damage. By raising both the cold-leg pipe and the loop seal, core uncovering can be prevented.



plants would allow pressure to be maintained by relatively smaller changes in water level during a transient, giving the operator more time to react and lowering the likelihood of having to bleed off pressure by opening relief valves.



error, that caused the accident at Three Mile Island.)

"The type of design changes being proposed for study in the new program should substantially reduce the financial risk to utilities of building new nuclear power plants," asserts Taylor. "The chance of a LOCA causing the type of damage we saw at Three Mile Island will be greatly diminished, which means that plant safety will also be enhanced."

Longer life and shorter construction

Several design changes will also be required to provide an extended life of up to 60 years for the new, optimized LWRs. Recent experiments show that radiation damage to the reactor vessel itself can be kept low enough for extended life by careful choices of vessel materials and by providing a larger ring of water between the core and the vessel walls. Some internal reactor structures may have to be designed for remote replacement in case they are weakened by irradiation, corrosion, or thermal fatigue. Improved decontamination methods should reduce the sort of internal contamination that leads to corrosion, however—a step that will also make maintenance easier and reduce radiation exposure to maintenance personnel.

To increase fuel reliability, designers will also consider lowering the amount of heat generated along each foot of a fuel rod. Currently this linear heat rate is about 14 kW/ft (4.2 kW/m) and studies will be made to determine the effects of lowering this rate to 9–10 kW/ft (2.7–3 kW/m). Such a reduction is expected not only to raise fuel reliability by placing less stress on the rods but also to lower requirements for the emergency core cooling system. By having lower power density, a reactor can be controlled with slower reaction times during transients. Because lower heat rates will require more fuel rods in a core, the new design is likely to cost more, and various other trade-offs will have to be investigated.

A recurrent theme running through many of the design changes now being considered is modularization. If new nuclear plants can be constructed with numerous shop-fabricated modules, the economy of scale once brought to large plants by conventional construction practices may be broken. Such a development would make a significant contribution both to large standardized plants through reduced costs and better quality control and to small plants by reducing their economic disadvantage of size.

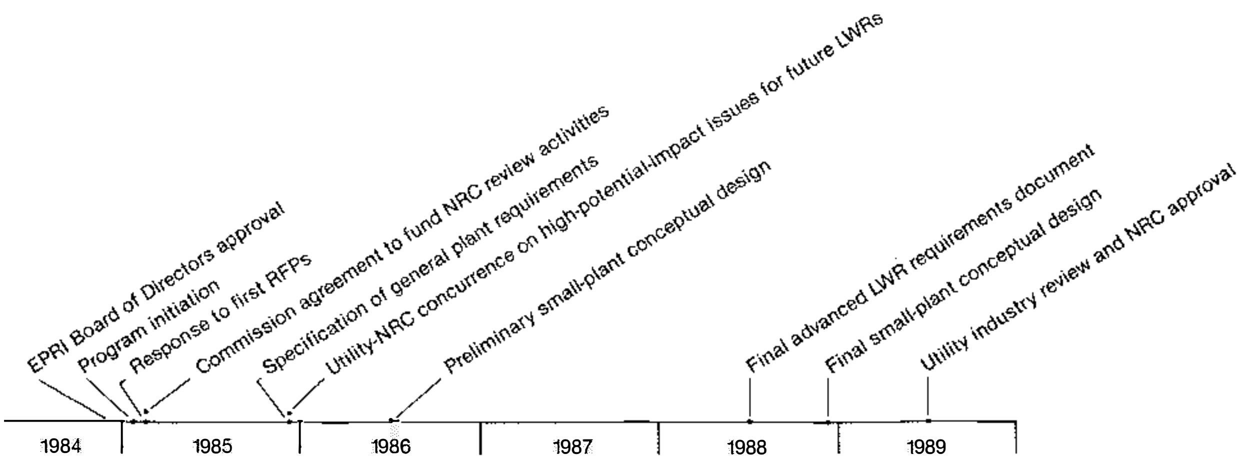
Off-site construction of modular units should help reduce the lead time and the total capital cost of nuclear plants, as well as reduce the risk to a utility from construction-related delays. Quality assurance is generally easier to maintain if major modules are shop-fabricated because of the more closely controlled environment of a factory and the learning curve improvements that come with experience in building many similar units. Modular construction can also facilitate standardization of plant components and improve overall construction control.

Two possible scenarios for building a modular plant might go something like this:

Large components are built at separate factories and shipped by rail for final on-site assembly, or a complete reactor and most of its safety-related systems are constructed on a barge at a shipyard. The barge would then be shipped by coastal and inland waterways to the installation site and floated into position over a ready-made foundation (reactor base mat). In either case, most of the shield building would already have been constructed, and

Milestones for Advanced LWRs

The national program will draw together the expertise of utilities, EPRI, NRC, reactor vendors, architect-engineers, major laboratories, and major universities to produce a detailed requirements document by 1990 that will specify the design of simplified, standardized LWR plants. Utilities will then be able to use the document to order a nuclear plant with assurance that it will meet industry standards and all current licensing requirements. In addition, conceptual plans for a small nuclear plant will be produced.



final plant preparation could proceed relatively quickly.

Toward smaller plants

The portion of the advanced LWR program devoted to small reactors will essentially try to determine whether modularization can be carried far enough to make nuclear plants economically viable in units of 600 MW or less. Such plants would offer utilities the option of adding new nuclear capacity in relatively small units, which may be better suited to uncertain growth projections and better able to compete with the small coal plants expected to be available in the 1990s. In addition, construction of small plants would require shorter lead times and less capital raised in a single bond issue.

The choice of whether to build large or small plants is becoming more complex. On the one hand, large plants have traditionally been cheaper to build on a per kilowatt basis. On the other hand, bringing such plants on-line often creates substantial periods of too much or too little generating capacity. During the period before a major plant is finished, for example, a utility may have to purchase power at high rates to meet rising demand. Then, suddenly, when the plant is finished, the utility may have excess capacity it cannot fully use. In addition, the construction delays that have increasingly plagued very large new plants can substantially add to the ultimate cost of the electricity produced.

Several unique features of small plants will be evaluated during the current program. The potential that small reactors have for increased natural circulation will receive particular attention, because this would reduce the amount of power needed for pumping and provide an extra margin against LOCAs. A small BWR might be able to operate entirely on natural circulation, which would eliminate the need for external recirculation loops. In a small PWR, enhanced natural circulation would reduce the potential for core damage during a LOCA in which pumped circulation is lost. (Ways are also being sought to increase the amount of natural circulation in larger plants up to 30% of total circulation, which could mean that smaller pumps might be used.)

By reducing the size of PWRs the use of soluble boron as a core poison might be eliminated. Boron carried by coolant in large PWRs absorbs neutrons and thus evens out the temperature distribution in a core, eliminating hot spots. The problem is that boron injection and removal is complex and expensive. In a small reactor the extensive fluid systems related to boron use may be eliminated if additional gray control rods are used to produce even temperature distribution. (Rods in a conventional PWR are black—that is, they absorb virtually all the neutrons that encounter them. Gray rods would absorb some predetermined fraction of the neutrons passing through them.)

For both types of smaller reactors, however, several trade-offs will have to be made between size and other considerations. The purpose of the current program is to establish an optimal level for such items as power density, pressurized volume, number of loops, vessel size, and so forth. Designers of improved small plants will then attempt to incorporate features unique to the small size, but they will not introduce unproven technology that would delay design introduction. The design will have to satisfy the requirements document, which is size-independent. Economic analyses will also be carried out to assess the effect of various trade-offs and to determine relative advantages of small plants. Preliminary economic studies sponsored by EPRI indicate that small plants might be able to cost as much as 20% more than large plants (in terms of overnight capital expenditures for construction, which ignore the time it takes to build a plant) and still be able to produce electricity at the same busbar price as a large plant.

Cooperation for a turnaround

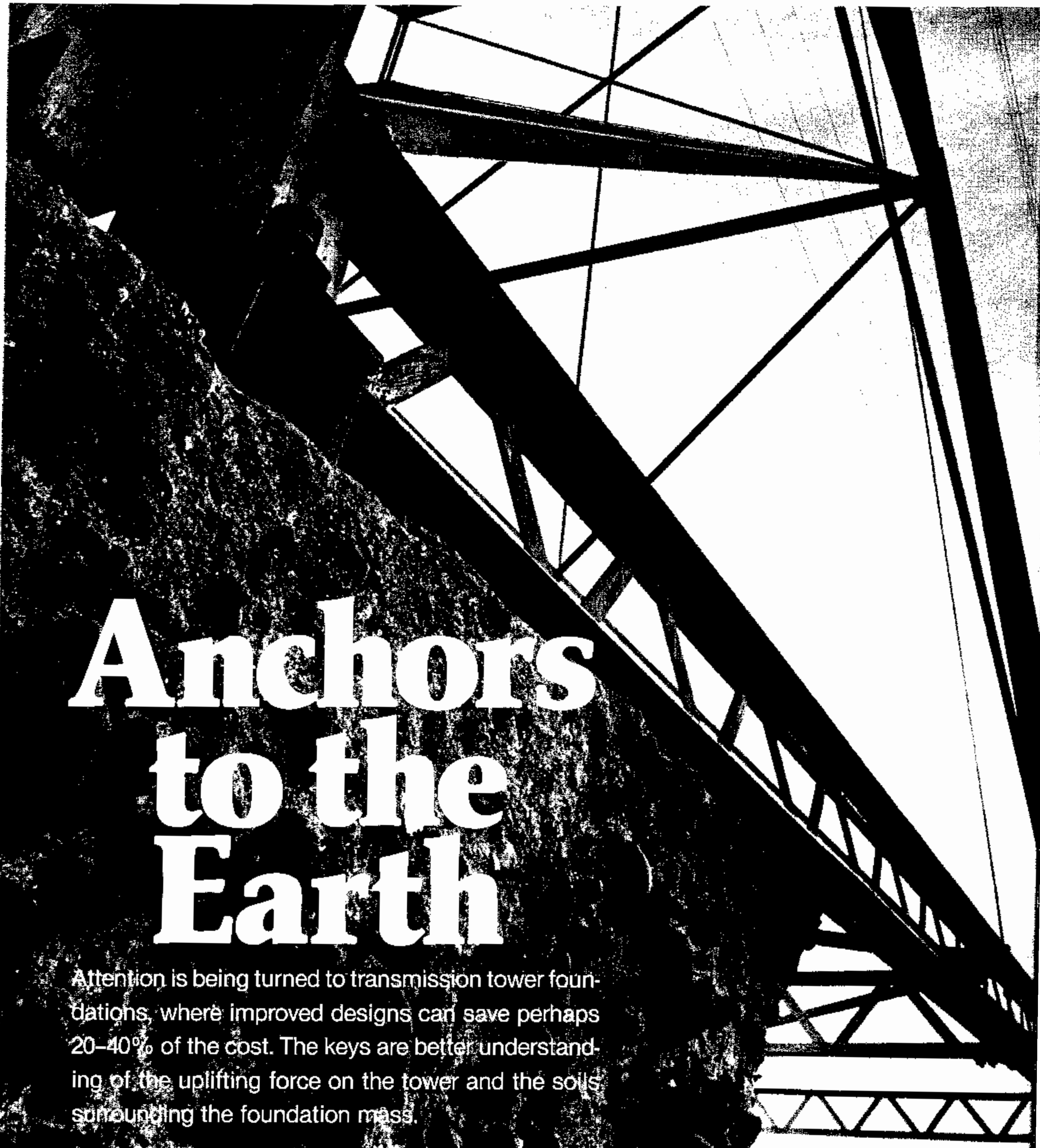
The new program began in January and final delivery of the simplified LWR requirements document and conceptual small-reactor designs is scheduled for 1989. During their meeting in December, EPRI's Board of Directors committed $20 million to the program. In addition, the monetary value of review efforts donated by NRC, nuclear suppliers, utilities, and the architect-engineers is expected to be at least as high as EPRI's direct cost.

Requests for proposals (RFPs) from contractors bidding to work on the requirements document were sent out during December and contractor selection was scheduled for the end of February. RFPs for the small-reactor portion of the program were to be released in January, with contractor selection scheduled to take place in March.

Overall guidance for the advanced LWR program is being provided by the Utility Steering Committee. Oversight of the program's budget comes from the Nuclear Power Division's Utility Advisory Committee and its Advanced Concepts Subcommittee. Various departments of the Nuclear Power Division are also providing assistance to the program through a management matrix—a cooperative effort involving shared management responsibilities within the division.

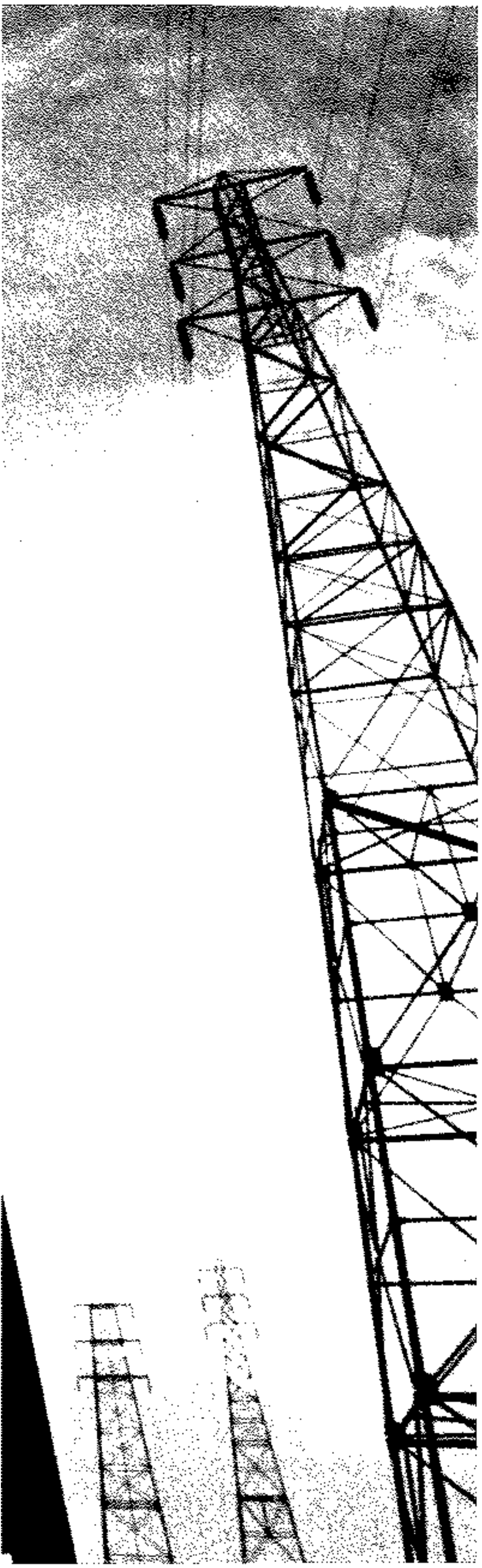
"I've never seen more cooperation between NRC and industry than in preparing for this program," states James A. Coffey, site director of TVA's Browns Ferry nuclear plant and chairman of the Nuclear Power Division's Advanced Concepts Subcommittee. "I believe this program can bring about a major turnaround in the future of commercial nuclear power plants." ■

This article was written by John Douglas, science writer. Technical background information was provided by Karl Stahlkopf and Warren Bilanin, Nuclear Power Division.



Anchors to the Earth

Attention is being turned to transmission tower foundations, where improved designs can save perhaps 20–40% of the cost. The keys are better understanding of the uplifting force on the tower and the soils surrounding the foundation mass.



Between now and the turn of the century electric utilities are expected to spend nearly $20 billion on new transmission lines. To help minimize this cost while providing utilities with improved methods for design and construction of these lines, EPRI's Overhead Transmission Lines Program is sponsoring a variety of research projects covering both the electrical and mechanical aspects of design. One area of the program that shows particular promise for offering large reductions in current costs concerns the design of transmission tower foundations.

"Although foundations represent only about 5–15% of the cost of a new transmission line, we believe that 20–40% of that cost could be saved through the use of better design methods," says Richard Kennon, program manager. "Very little has been written about how to design foundations that can cope with the unique loading conditions encountered by transmission towers. Recent work sponsored by our program shows how the design process can be greatly simplified so that utilities can realize considerable savings on their transmission line foundations."

The problems facing designers of such foundations are special for several reasons. Although most structural foundations—like those that support bridges and buildings—are designed mainly to hold compressive loads caused by the weight of the structure above, the controlling design load of a four-legged transmission tower foundation is often uplift. The reason is that a tower is subjected to forces that try to tip it over and thus exert an upward pull on two of its legs. Such forces can result from wind, from ice falling off lines, or from unequal loads experienced during construction.

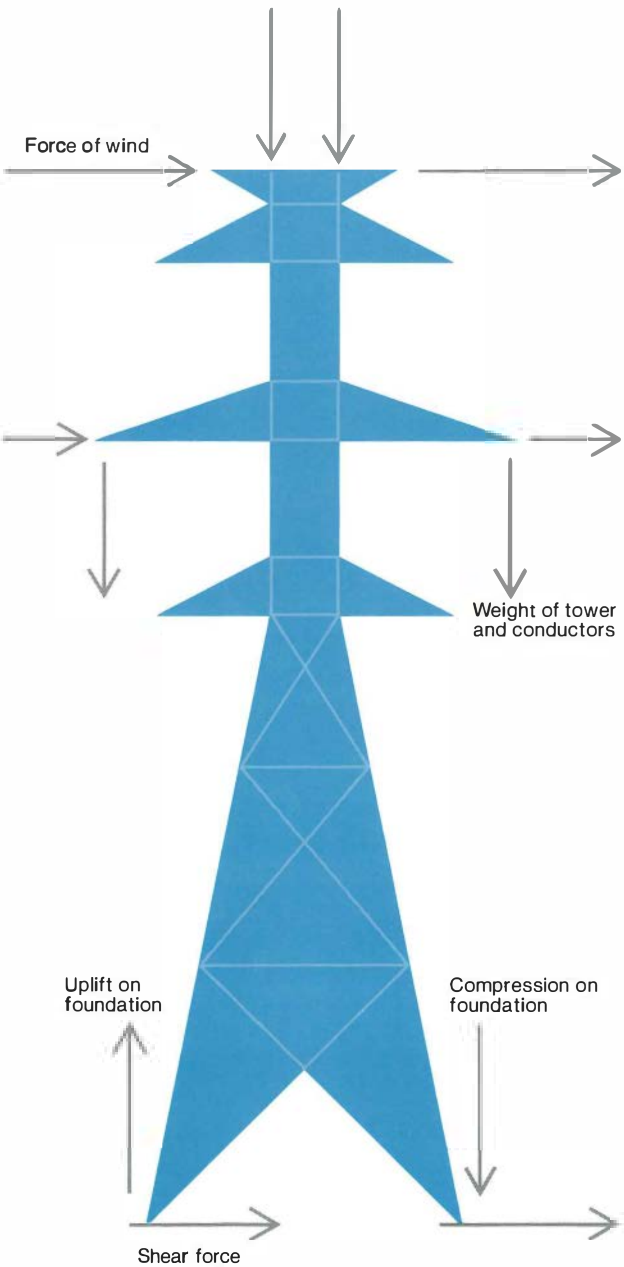
In addition, because so many separate foundations must be constructed along a transmission line, only limited information can affordably be gathered about the ground characteristics at each site. Engineers working on foundations at sites of bridges and major buildings routinely investigate site geology, groundwater, and soil and rock conditions in great detail. A transmission line design team, however, relies heavily upon information that is already available from air photos and geologic maps. Where onsite ground evaluation is required, careful trade-offs have to be made between the cost of various testing techniques and the amount of useful information each can provide.

To help utilities meet this challenge, an ongoing EPRI project has recently produced the first unified model for design and evaluation of transmission tower foundations subject to uplift and compression loading (EL-2870). This model has also been compared recently with results gathered from more than 800 field load tests, which proved the proposed design methodology both reliable and generally applicable, subject to certain limitations (EL-3771). Future reports based on the project work will address combined and cyclic loading conditions. The research is being conducted by the Geotechnical Engineering Group of Cornell University.

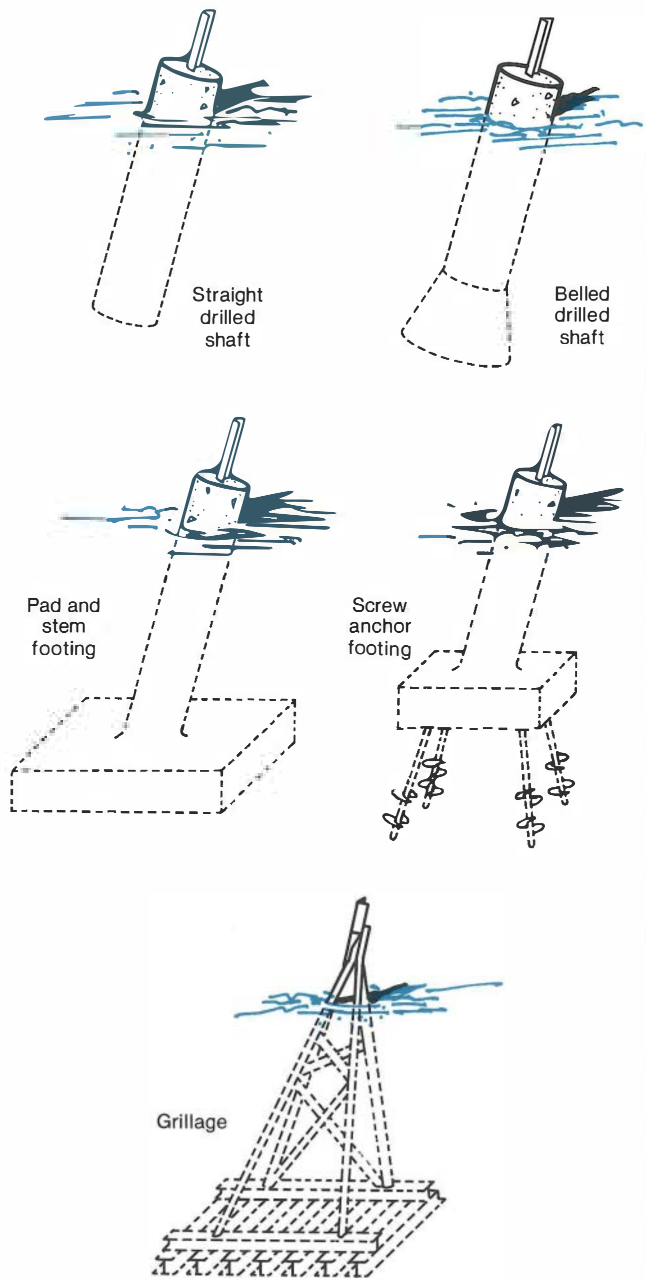
Foundations as transmission line components

Foundation design is often one of the last steps in a long planning process that precedes actual construction of a transmission line. (Some of the steps of this process are actually carried out in parallel with others.) First the line end points and overall line parameters (e.g., voltage, capacity) are determined. Possible line routes are then identified by considering a host of factors, including the placement of substations, patterns of development, local climate conditions, environmental features, and underlying geologic characteristics. After the tower type has been selected, final tower design can be completed and tested. Only during actual tower site selection can individual foundation designs be finalized, taking into account the variety of difficult and often conflicting requirements created by the rest of the process.

Lattice towers and their foundations are subject to a number of forces that must be taken into account in their design. The basic vertical force derives from the dead weight of the tower and its conductors. The wind contributes a horizontal force on the tower, producing not only a horizontal shear force on the foundation but also an upward (uplift) force on the windward side of the structure and a downward (compression) force on the other. These uplift-compression forces are the ones of primary concern in foundation design.



About 70% of four-legged tower foundations are of the drilled-shaft type, making this the design of choice for most applications. Spread foundations, which use grillages or pad-and-stem designs, are also common options, especially when a site allows only shallow excavation; grillages are frequently used in remote areas and where difficult terrain precludes easy access for concrete-pouring equipment. The screw anchor footing is a hybrid design not yet in widespread use. Although the examples shown are for 4-legged towers, the same basic designs are also used for 1- or 2-pole structures.



The type of loading that controls foundation design depends most of all on the kind of towers being used along a line. The controlling design load for four-legged lattice towers is vertical uplift and compression. Foundations for two-legged structures, or H-frames, must be designed to withstand overturning moments as well as shear and uplift forces. Overturning moments dominate foundation loading for single-pole structures. And guyed structures produce mainly vertical and shear loads on the tower foundation. Given this information, foundation designers must next determine the specific loads that will be encountered. Everyday loads result from the dead weight of a structure, differential conductor tension, line angle, and so forth. Weather-related loads can be caused by the forces of wind or ice on the conductors and towers. Failure containment loads are also considered for events that cannot be foreseen but which may nevertheless cause a mechanical failure. Often the tower foundation design is determined by loads that do not occur every day, a circumstance not usually encountered with other types of engineered foundations. Construction and maintenance loads, though more controllable, can also be severe—for example, when conductors are attached to only one side of a two-circuit tower.

To meet these various demands, several types of foundations have evolved. Perhaps the most common type currently used is the drilled shaft, which is constructed by augering a cylindrical hole and filling it with reinforced concrete. The diameter varies from 3 to 10 ft (0.9–3 m) and the shaft depth, from 10 to 50 ft (3–15 m). Whether a drilled shaft moves vertically in response to uplift load depends largely on the friction between ground and shaft, and an important contribution made by the current research has been to find ways of quantifying this resistance.

When the drilled shaft is used for single- or two-pole structures, overturning moment (rather than axial loading) may govern foundation design. Results of another EPRI research project are available for such designs (RP1280). The computer code PADLL, which has been distributed to more than 100 EPRI members, is used for design of such high-moment foundations.

Related to the drilled shaft is the direct embedment foundation. In this case, the pole is placed in an augured hole and the annulus backfilled with soil, gravel, or grout. This is a common placement method for wood poles and it is now being used for steel and concrete poles as well. The historic and almost universally adopted design for wood structures is that the embedment must be 10% of length, plus 2 ft (0.6 m). Wood poles of normal size have a limited moment capability, but steel and other higher strength materials allow greater moment loading of the direct embedment foundation. The old rule of thumb is not adequate for these more heavily loaded structures, but no verified design model is available. Follow-up work is now under way to adapt PADLL to model the direct embedment of these structures. Field tests will then be conducted to verify and calibrate the model.

Where ground conditions require them, pile foundations are used. These are long, slender piles driven into the ground, and may be made of steel, precast concrete, wood, or a composite of these materials. Several driven piles are placed in a closely spaced group to form a complete foundation. A concrete cap is cast on top of this group of piles to provide structural integration.

For shallow excavations, a spread foundation with a broad base is placed in an excavated hole and backfilled. Such foundations can consist of either a concrete footing cast in place or a prefabricated steel frame that can be flown by helicopter into inaccessible areas. A related type of foundation involves anchors connected to a spread-type pad. These foundations use the anchors to resist uplift loads and the pad to resist compressive loads.

Many other factors can also affect the choice of the type of foundation used. Loading conditions, field conditions, local practice, material availability, and cost must sometimes be considered. Regardless of this selection, however, the ability of the design engineer to quantify foundation response to loading is crucial.

Toward a unified model

Over the years many models have been proposed for calculating the resistance to uplift of various kinds of foundations under specific circumstances. The problem with these models has been that the results could not be extrapolated very well beyond the narrow set of conditions for which the models were developed. A key accomplishment of the current research has been the development of a unified model that is much more applicable.

"Most earlier models were tested only over a very limited range of ground conditions," comments F. H. Kulhawy of Cornell. "By bringing together this information on a unified basis, we have developed a sound and rational set of design criteria that predict how a foundation actually behaves and that can be applied under a full range of ground conditions."

The first step of the method is to determine the in situ horizontal stress exerted by the soil on the surface of a foundation, as well as the soil strength parameters. During the project, various ways of measuring the soil parameters that are used in determining this stress have been reviewed. In the standard penetration test (SPT), a 140-lb (64-kg) weight is dropped 30 in (76 cm) to drive a sampling spoon into the ground. The number of blows required to push the spoon a given length is then correlated with a number of soil properties. The advantage of SPT is that it is relatively quick, simple, and inexpensive; but it is also subject to many kinds of errors. Also, correlations of the SPT measurements with those of soil stress and other parameters are not particularly reliable.

A faster way to identify potential problem soils is the cone penetration test (CPT), in which a shaft with a conical tip is slowly pushed into the ground while electrical transducers measure both tip pressure and side friction. The CPT generally gives more-accurate measurements than the SPT, but many drilling contractors lack the necessary equipment because of low demand.

For clays that range from soft to medium-stiff, the vane shear test (VST) provides a rapid and economical alternative. In this test a four-bladed vane is pushed into a clay stratum and slowly rotated while the resisting torque is measured. The disadvantage of the VST is that it is limited mainly to clay strata that have already been identified by some other test or soil sampling procedure.

Only one kind of test is able to measure soil stress directly. In this pressuremeter test (PMT) a cylindrical probe is placed down a borehole and then expanded into the soil by using a pressurized liquid or gas. Although the PMT shows promise for future state-of-the-art design because of its ability to measure stress patterns directly, its use now is limited because many contractors lack the necessary equipment, and like the VST, it is used mainly to test strata previously identified by other means.

After natural ground conditions have been measured, an analysis must be made of the extent to which these conditions will be modified by the proposed construction. For example, the breakout pattern of soil surrounding a spread foundation that is pulled out of place by uplift forces can vary greatly, depending on the type of backfill that has been used and the placement technique employed. Failure of a shaft-type foundation occurs primarily as a cylindrical shear that pulls up a limited amount of soil along its surface. The size of this collar of soil also depends on the type of construction methods used.

Once the critical soil parameters and their modifications due to construction have been determined, the uplift resistance of the foundation can be calculated. This calculation involves numerical integration of ground stress along the vertical surfaces of the foundation. Relatively simple design equations have been developed for this purpose. These equations have been calibrated by load test comparison and sophisticated finite element analysis, a major computation task requiring a large computer. (This type of analysis involving numerical arrays with as many as 5 million unknowns could not have been performed with the computers available 10 years ago.) In addition, some resistance to uplift may result from tension or suction on the bottom surface of a foundation, particularly in undrained soils. This resistance, although usually not as important as that along the sides of a foundation, can be calculated by simpler procedures.

Tests and applications

To establish the general usefulness of the unified model for transmission tower foundation design, the results of calculations by using the model have been compared with 804 actual field load tests. These tests involved determining the capacity of full-scale foundations to withstand various loads, as well as measuring the amount of uplift movement that accompanied the loads. Results of the tests were taken both from published reports and from unpublished information made available to EPRI by its member utilities.

Comparison of test results with those predicted by the unified model generally showed close correlation. There were, however, some areas of discrepancy, which either indicated limits of the model or revealed places where modifications were needed.

In particular, the ground resistance along the sides of a drilled shaft foundation could be predicted reliably, but the tip resistance in drained soils was sometimes overestimated. For driven piles, the side resistance was predicted well for undrained soils, but improvement is needed in refining the influence of construction on drained soils. (Tip resistance was not evaluated for driven piles.)

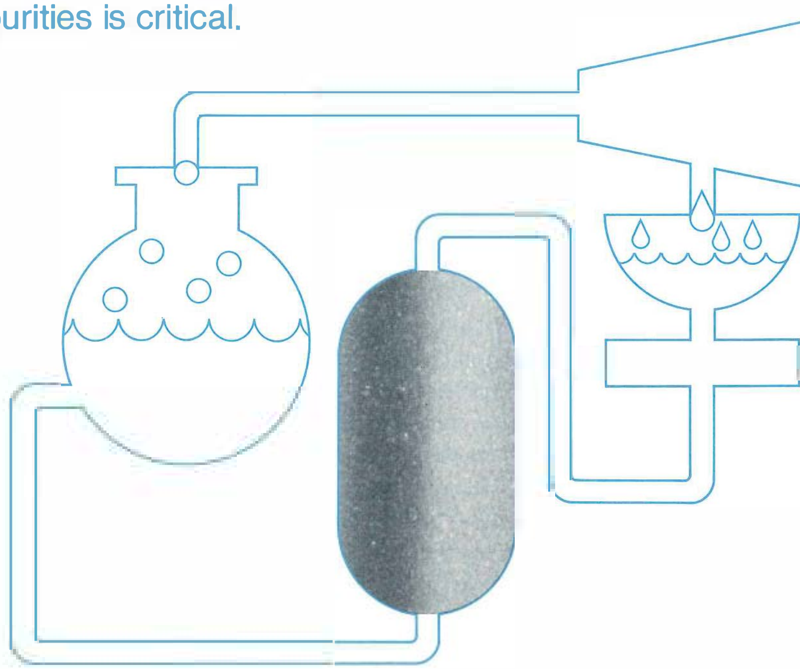
Reasonable predictions were made about the uplift capacity of spread-type foundations, but better field data are needed to evaluate the effect of various kinds of backfilling. The results on uplift movements were not as satisfactory, and more detailed data will be needed before improvements can be made.

"This is ground-breaking work," explains Vito Longo, EPRI's project manager. "We're removing a lot of mystery in a design area where it has been necessary to greatly overbuild because of a lack of hard data. The information produced by this project will help make foundation design more efficient in two ways: It creates a possibility for building more-economical foundations, and it quantifies the actual response characteristics of foundations, making them more predictable. The ongoing work in this project will further the goal of being able to really design foundations, as opposed to overdesigning them because we didn't have a credible design model."

This article was written by John Douglas, science writer. Technical background information was provided by Richard Kennon and Vito Longo, Electrical Systems Division.

Chemical Filtration for Steam Purity

Impurities inevitably migrate into the steam cycle and must be removed to prevent turbine blade corrosion. Understanding the behavior of the condensate polishing resins used to remove the impurities is critical.



Few industrial process systems are as vulnerable to corrosion as the steam generating loop of an electric power plant. The ideal is a closed system in which a constant amount of pure feedwater is vaporized and superheated, expanded against the blading of one or more steam turbines, condensed to liquid form in a vacuum vessel, and then circulated through feedwater heaters and pumps to commence the cycle over again.

The reality is different in one important respect: the system is not truly closed. Feedwater and steam follow the same path, but there is continual inleakage of air and water, notably at the condenser, where thousands of heat exchange tubes include some number of leaky joints and where vacuum conditions exert a powerful suction into the system.

Condenser cooling water, whether fresh or salt, introduces any number of corrosive agents, the principal ones being chlorides, sulfates, and sodium, the dissociated ions of several salts. And air, of course, brings oxygen and carbon dioxide into the system. Despite these contaminants and their consequences, feedwater and steam purity must be maintained. That is the function of condensate polishers, placed in the loop downstream from the condenser.

Problem with regeneration

Polishers are large, rubber-lined steel vessels that contain beds of specially treated synthetic resins through which the condensate is passed. The resins give up harmless ions and adsorb harmful ones. These exchanges are driven by differences in ion concentrations of the species, as well as by inherent thermodynamic selectivity. Thus, cation (positive) resins release hydrogen or ammonium ions while attracting sodium from the condensate. Similarly, anion (negative) resins give up hydroxyl ions while capturing chloride and sulfate ions.

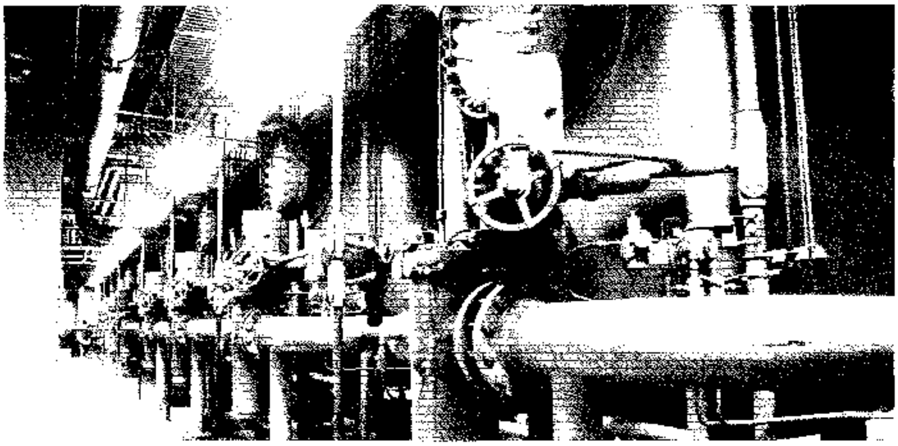
As resins become saturated with contaminant ions, their removal efficiency drops, so polishers are periodically taken out of service (isolated by means of valves) for chemical regeneration. When this procedure itself becomes an unsuspected—and major—source of contaminants, the results are inexplicably higher polisher operating costs, followed by a thorough sense of frustration among power plant operators, and topped off by costly repairs of corrosion-damaged turbines.

This was exactly the situation at Southern California Edison Co. (SCE), where severe pitting and stress corrosion cracking was unexpectedly found in the low-pressure turbine blades of several once-through supercritical turbine generator units. Two low-pressure turbines were so severely damaged that one or two rows of blades had to be replaced after only 4 years of a normal 12-year blade life. The corrosion was traced to a very high chloride level in the steam, but the source of the contaminant remained a mystery.

Regeneration procedures were not quickly seen to be the problem. SCE's practice was to regenerate polisher resins on the basis of contaminant levels in the condensate at the polisher discharge. Following accepted industry practice, the utility was measuring acid conductivity and sodium values, relying on the former as an indicator of total anions (including chloride and sulfate). Although acid conductivity and sodium were being held within bounds by the SCE regeneration schedule, special measurements revealed that chloride levels were somehow running many times higher than acceptable.

SCE's mystery could be seen simply as one utility's problem. But the detective story had wider ramifications. Clearly, a better understanding of polisher operation and steam chemistry was needed. These were already topics of concern in three EPRI research departments. Moreover, EPRI was seeking a host utility to

Six or eight condensate polishers may be connected in parallel to serve a single generating unit. One or more can be withdrawn from service for regeneration.



test corrosion-resistant coatings then under development for low-pressure turbine components; so SCE and EPRI joined forces in field and laboratory research.

Ion chromatography

Among other things, the new investigation called for the detection and measurement of contaminant levels of less than one part per billion (ppb). EPRI supplied several analytic instruments to SCE for evaluation of sensitivity, consistency, and accuracy; and one of them, the then-new ion chromatograph (a modified Dionex model 14), proved to be particularly useful.

In fact, ion chromatography showed chloride levels at the SCE polisher discharge to be more than 20 ppb, 10 times the desired limit. By immediately stepping up its regeneration schedule, SCE was able to reduce chloride levels by 50%, to about 10 ppb. This had a positive effect on turbine blade life: at the next unit overhaul, only a small number of blades, rather than entire rows, had to be replaced. However, the degree of corrosion pitting was still unacceptable.

Ion chromatography also was the sleuth that revealed how the polishers themselves, despite frequent regeneration, were the main contributor of chloride to otherwise thoroughly polished condensate. This unprecedented conclusion emanated (after understandable doubt and skepticism) from laboratory research.

During normal polisher operation, the hydrogen ions of a cation resin are gradually stripped (replaced) by ammonium, one of the ions of the ammonium hydroxide that is added to feedwater for pH control. When its cation resin is thus mostly ammoniated, the polisher is said to be operating beyond ammonium breakthrough.

Depending on various factors that deplete ions at different depths in the polisher (such as condensate composition and flow rate), reactions involving ammonium and hydroxyl ions may also affect chloride exchange in the anion resin. Thus, for example, chloride removal is most efficient before a cation resin passes ammonium breakthrough. Even more important, if anion resins near the bottom (discharge) of the polisher accidentally retain chloride ions during a faulty (incomplete) regeneration, after breakthrough on the next polisher run, hydroxyl ions will strip those chloride ions and reintroduce them into the condensate stream leaving the polisher.

Now it was apparent why more frequent regeneration—thus avoiding ammonium breakthrough—was providing some relief for SCE by cutting chloride levels. But the pivotal finding was that the caustic chemical (a 50% sodium hydroxide solution) used to regenerate SCE's anion resins was the culprit because of its own 6000-ppm chloride content, some of which was remaining in the anion resin at the end of the regeneration process. When the polisher was later operated beyond breakthrough, chloride levels in the polisher effluent (discharge) were often twice as high as in the influent (inlet).

New regeneration chemicals

With the source and action of chloride thus identified, the SCE researchers turned to means for precluding its accumulation during polisher regeneration. SCE was also painfully aware of the extra operating cost entailed by frequent regeneration. If a polisher could be operated past breakthrough and still remove all designated contaminants effectively, regeneration would be less frequent and less costly.

Two changes in procedure showed promise: treating the anion resin with sulfuric acid before regeneration, and using low-chloride (100–300 ppm) caustic to regenerate the anion resin. The pretreatment scheme works because sulfate is a more selective species than chloride, thus more thoroughly displacing chloride from the resin beds. Low-chloride caustic at first proved to be more easily recommended than used because it was difficult to obtain on the West Coast in sufficient quantity for polisher regeneration.

Although each method by itself yielded a significant reduction of chloride level in polisher effluent, a combined use proved the most effective. One condensate polisher, for example, having been treated with both sulfuric acid and low-chloride caustic, was later monitored in field tests and showed an effluent level of less than 1 ppb chloride for 30 days following ammonium breakthrough. During that time it processed 80 million gallons (303,000 m^3) of condensate. This polisher also was the first that SCE ever operated past ammonium breakthrough with less than 5 ppb chloride concentration for an entire run, processing nearly 173 million gallons (656,000 m^3) of condensate at a prescribed average influent pH of 9.5.

Another good sign was the extended capability of the polisher for removing sodium from condensate. Even beyond breakthrough, sodium levels in the polisher discharge were less than 5 ppb throughout the run, indicating good separation of cation and anion resins during the preceding regeneration.

Despite early indications of success, the research team questioned the long-term effect of sulfuric acid on anion resins. They particularly considered the possibility of silica polymerization and resin degradation from osmotic shock. This led to trial use of ammonium sulfate as an alternative for anion resin treatment. Subsequent ion chromatograph analyses showed average chloride, sulfate, and sodium leakages from the polisher (after ammonium breakthrough) to be 0.9, 1.1, and 2.4 ppb, respectively.

Thus confirmed by field trials and laboratory analyses, SCE's modified anion regeneration procedure now consists of ammonium sulfate treatment of the resin, followed by low-chloride caustic. Cation regeneration consists of ammonium sulfate treatment of the resin before and after ammonia recirculation, followed by a dilute ammonia rinse. As a result of the new routine, the polisher goes into service with its cation resin already in ammonium form. Then, if initial readings of sodium and sulfate leakage are higher than desired, which sometimes occurs, a second regeneration cycle can be carried out.

Follow-on studies

The significance of SCE's many sharp changes in the operation of its condensate polishers is summarized by David Auerswald, senior chemical engineer in the chemical section of the utility's steam division. "As a result of our joint work with EPRI, we've reduced our turbine corrosion dramatically. If there's only slight cooling water inleakage, we can operate well-regenerated condensate polishers past ammonium breakthrough with less than 1 ppb of chloride, sulfate, and sodium leakage."

The EPRI–SCE project team also studied the effect of cooling water intrusion by simulating condenser leaks. They found that during high influent contamination (especially by sulfate), resin condition is a primary determinant of performance. When condenser inleakage is only moderate, a properly regenerated polisher with resins in good condition can be operated past ammonium breakthrough with polisher effluent levels of sodium, chloride, and sulfate held to less than 2 ppb. Moreover, a removal efficiency of at least 98% can simultaneously be maintained.

As a final test note, field and laboratory studies showed that SCE's modified regeneration procedure does not increase the precipitation of calcium or magnesium on the anion resin, nor is there any indication of resin fouling.

SCE found the path to better polisher performance only after laborious field testing and comprehensive laboratory analyses. The expected payoff is a reduction of some $400,000 annually in turbine repair and polisher operating costs.

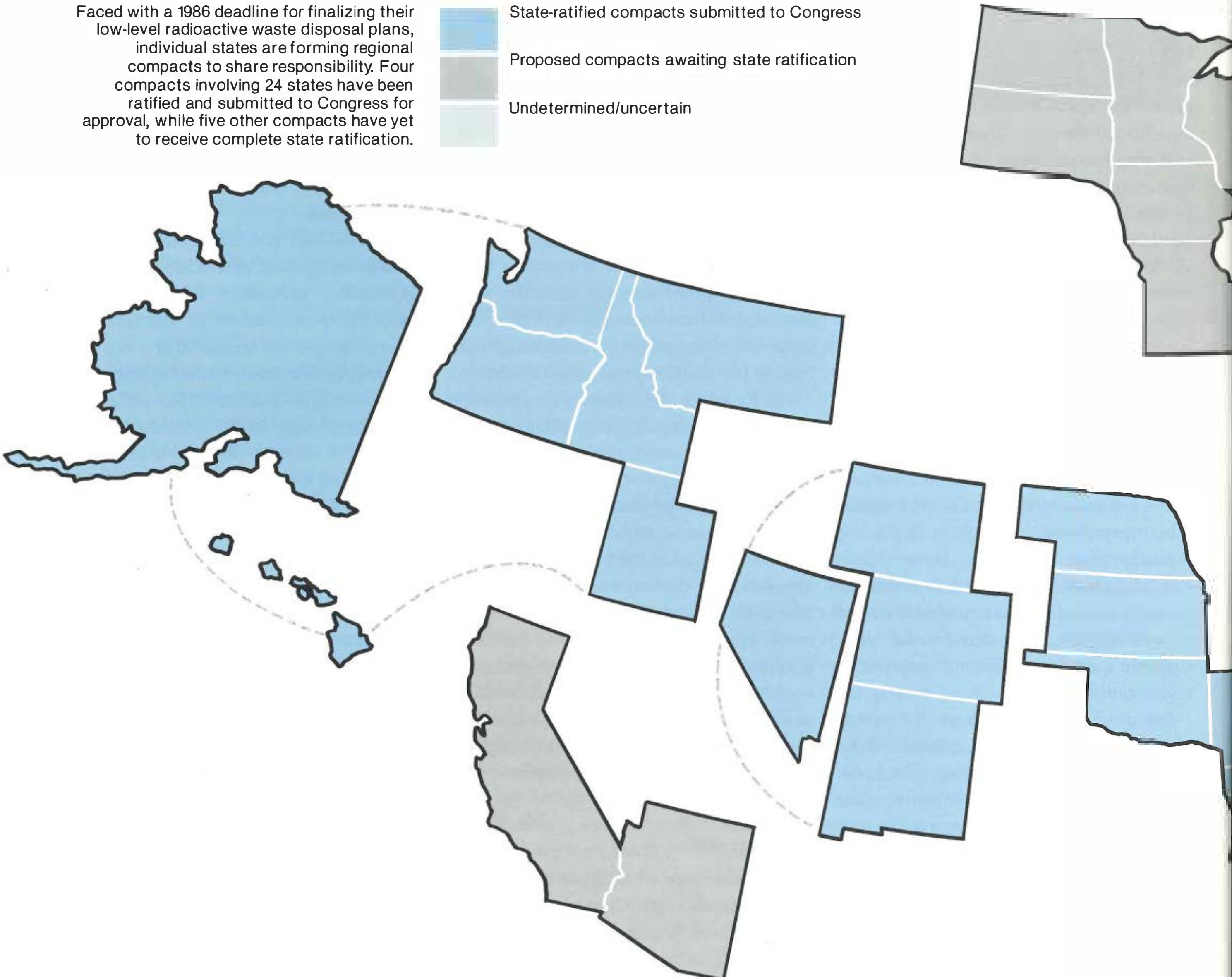
Now going beyond the original chemical mystery and its labyrinthine solution, SCE is studying the dynamics of regeneration and the optimal physical and chemical characteristics of polisher resins. Auerswald and his colleagues are looking at levels of fluoride and a group of organic acids in the steam cycle. As Auerswald puts it, "The ion chromatograph became such an integral part of our studies that we bought two instruments of our own for steam chemistry analysis. We are really defining what condensate polishers can and can't do, and how to get high-quality water." ■

This article was written by Francis Kovalcik, science writer. Technical background information was provided by Barry Syrett, Materials Support, R & D Group; and Thomas Passell, Nuclear Power Division.

The Great State of Uncertaint

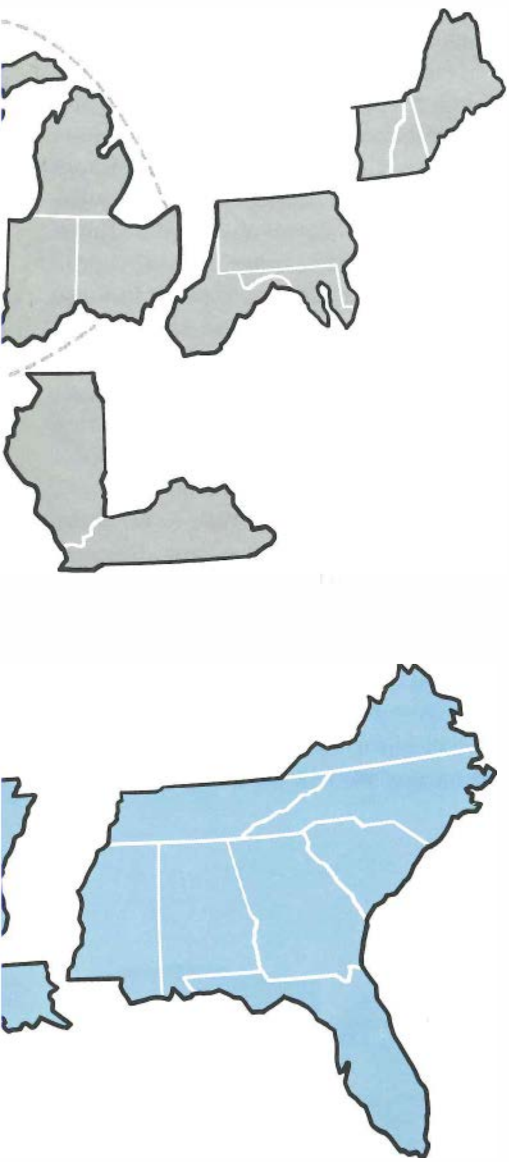
Technical options for safe disposal of low-level radwaste have be

Faced with a 1986 deadline for finalizing their low-level radioactive waste disposal plans, individual states are forming regional compacts to share responsibility. Four compacts involving 24 states have been ratified and submitted to Congress for approval, while five other compacts have yet to receive complete state ratification.



in Low-Level Waste Disposal

eveloped, but their application has been stalled by tough institutional problems.

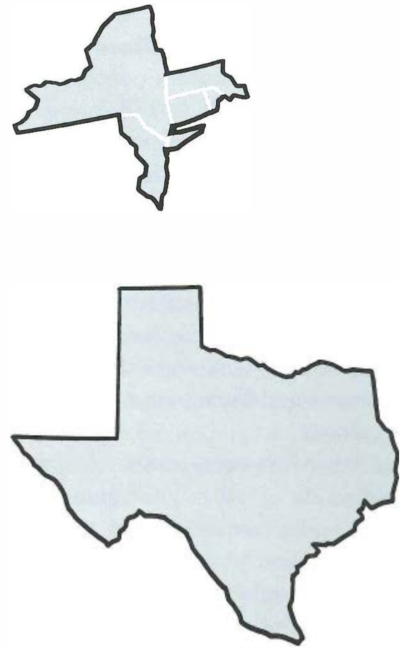


When the clock strikes midnight next New Year's Eve, most utilities—as well as thousands of hospitals, research laboratories, and industrial concerns—may confront the reality of having nowhere to dispose of low-level radioactive waste. That's the deadline for each of the 50 states to have assumed responsibility for waste generated within its borders; January 1, 1986, is also when states now operating low-level radwaste disposal sites may begin refusing to accept the nuclear waste of others.

Such an apparent impasse most certainly was not what Congress intended when it enacted the Low-Level Radioactive Waste Policy Act in 1980. The law was designed to encourage states to form regional compacts that would cooperatively plan and operate disposal sites, thereby more equitably allocating the economic and political costs that are now borne by three states with active sites: Nevada, South Carolina, and Washington.

More than 34 states have since joined multistate compacts, yet to date no new site for low-level waste (LLW) has been selected by the newly formed alliances. Several states have launched extensive efforts to evaluate potential sites and establish waste management programs, but the political anathema embodied by the "not in my backyard" response of the public has, in most cases, kept progress to a crawl.

Connecticut, Massachusetts, New Jersey, New York, and Rhode Island have not yet arranged interstate alignment, and their plans for LLW disposal remain uncertain. Texas chose to plan for LLW disposal on its own and has begun a site selection process.



Meantime, the more than 20,000 medical and academic institutions, laboratories, government agencies, and industrial companies—including utilities operating nuclear power plants—that generate LLW face an increasingly uncertain future for disposal options. These sources now produce an annual volume of about 77,000 m^3 of LLW containing around 500,000 curies of radioactivity; a DOE study predicts annual volume could more than double by 1990.

The situation follows a decade in which the cost of shallow land burial of a 55-gal drum of LLW has increased 10-fold. For an example of particular interest to utilities, the cost of burying a drum of various boiling water reactor (BWR) waste streams at the Barnwell, South Carolina, commercial site increased 227–295% between 1980 and 1983 alone.

"Low-level waste disposal is in a state of transition," says Michael Naughton, a project manager for radioactive waste and coolant technology in EPRI's Nuclear Power Division. "As recently as 1975 the disposal of such wastes was viewed as a rather straightforward proposition. Costs were in line with other operating expenses and burial site availability was assumed.

"Now, however, utilities, as well as thousands of other generators of low-level waste, are having to make long-term disposal plans in the face of substantial uncertainties regarding many of the variables controlling cost and site availability," Naughton adds.

In response to the changes of the last 10 years, EPRI is sponsoring a broad research effort on LLW disposal, ranging from more-accurate and less-expensive waste assay methods to studies of volume-reduction systems and other waste minimization techniques, solidification criteria, and evaluations of disposal economics. The work is helping provide utilities with the information they need to chart economically and technically sound strategies for disposing of wastes, whatever the effects of unpredictable political and institutional outcomes.

LLW and disposal experience

As defined in the 1980 law, low-level radioactive waste is any material not classified as spent reactor fuel, high-level waste (from reprocessing reactor fuel), transuranic waste (containing significant amounts of such long-lived isotopes as those of americium or plutonium), or uranium or thorium by-product material, such as mill tailings. The Nuclear Regulatory Commission (NRC) carries the definition a step further, specifying that LLW should be acceptable for underground disposal and defining subclassifications according to the degree of care required for disposal.

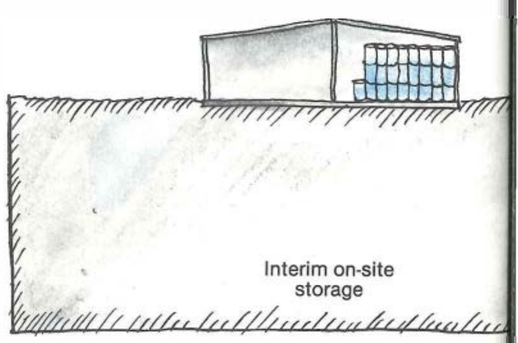
Nuclear power plants operated by utilities in 25 states accounted for about 66% of the waste volume shipped to commercial disposal sites in 1982; the utility sector's share of the total radioactivity of waste disposed of in that year was a slightly higher percentage. LLW from nuclear reactors includes dry trash, used equipment, and solidified liquids and sludges. Items range from spent resins from ion-exchange processes, filter materials, lubricating oils, contaminated tools, clothing, and packaging (which have relatively low levels of radioactivity) to irradiated reactor components, such as in-core instrumentation and control rods (which typically contain higher levels of radioactivity).

Nearly all the remaining LLW comes from a variety of institutional and industrial sources, including hospitals, universities, pharmaceutical companies, nuclear fuel fabricators, and other manufacturers spread over all 50 states. These sources produce a range of waste types, as do nuclear reactors, but the isotopic content of industrial and institutional wastes can be quite different, depending on the specific application.

Until the 1960s most low-level wastes were disposed of at sea in steel drums—an expensive option that later gave way to shallow land burial as wastes were shipped to federally owned disposal sites. But as the volume of commercial waste grew with the increased use of nuclear energy for power production, commercial burial sites were licensed by individual states and became the principal facilities for LLW disposal, including some government defense-related LLW.

Engineered Storage and Disposal Options

With a potential shortage of shallow land burial capacity looming, some utilities are planning for interim on-site storage of LLW until new burial sites are developed. Meanwhile, many states are considering engineered alternatives to shallow land burial in the face of current political uncertainties. Engineered approaches range from earth-mounded concrete bunkers and augured holes for concrete containers to above- and below-ground vaults and mined geologic cavities. Such approaches are under development in other countries as well. France, for example, is pursuing the concrete bunker approach, while Sweden proposes to excavate a coastal granite formation beneath the sea. All the engineered methods, however, entail substantially higher cost than shallow land burial and, EPRI believes, offer only marginal added safety. For the same reason, Japan plans to use traditional shallow land burial in its LLW disposal program.



During the late 1960s and early 1970s the nation had six commercial disposal facilities—operating in Illinois, Kentucky, Nevada, New York, and South Carolina and at the Hanford federal reservation in Washington.

For a time, these sites served the country's needs for shallow land burial capacity. Long trenches, each about 15 m deep, were dug, filled with drums or other waste packages, backfilled with earth, and covered with clay caps to minimize the infiltration of water that could cause leaching of radioactivity. Yet it was problems of precisely this nature that in 1975 led to the closing of the West Valley, New York, site and, two years later, of the site at Maxey Flats, Kentucky. Both sites now are closely monitored for radioactivity migration from the trenches.

In 1978, after protracted negotiations between the state and the operator over expanding burial capacity, the Sheffield, Illinois, site was also closed. Water infiltration of trenches has since become a concern there as well.

With three of the six commercial sites closed, the governors of Nevada, South Carolina, and Washington became concerned about their states' accepting all of the nation's LLW. They urged Congress to develop a plan to make each state responsible for disposing of LLW generated within its borders. Moreover, the governors of Nevada and Washington temporarily closed the Beatty and Richland sites, respectively, in 1979 in protest against packaging and transportation rule violations in some waste shipments. And the following year South Carolina announced it would increasingly limit the amount and type of waste acceptable at the Barnwell site.

As matters now stand, only the Richland and Barnwell sites are accepting significant amounts of commercial LLW. Third-party inspection requirements and associated additional charges at the Beatty site have reduced the volume shipped there to about 2% of the LLW disposed of commercially; the site reportedly will soon be closed. Washington State continues to express a desire to limit shipments to the Richland site to those wastes generated in the Northwest.

States forming compacts

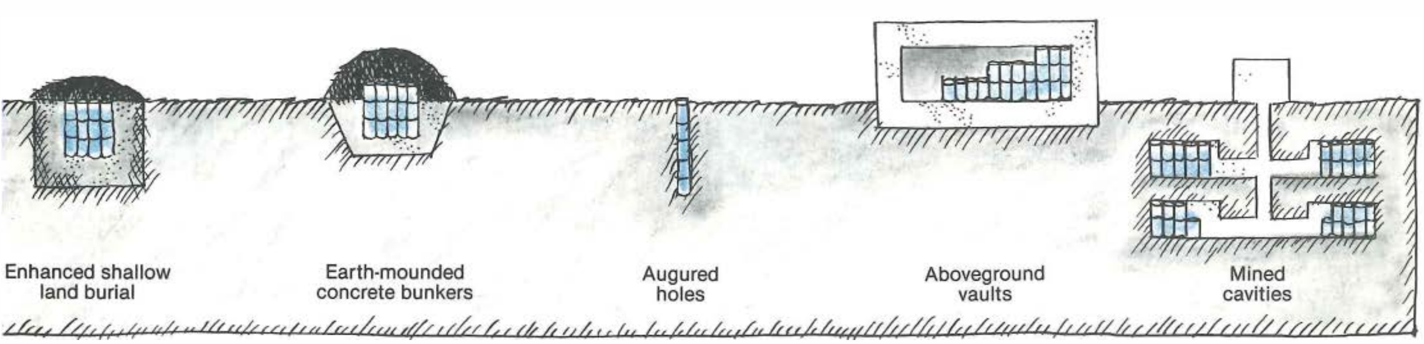
With a serious shortage of LLW disposal capacity looming by the middle of the decade, a combination of state and federal government initiatives led to enactment of the Low-Level Radioactive Waste Policy Act in late 1980. Declaring LLW disposal to be the responsibility of the states, the act recommended the formation of regional compacts that would provide for disposal in accordance with NRC licensing criteria. Member states in a compact could exclude other states from using their disposal facilities after January 1, 1986. Congressional approval was required for a compact to take effect.

Soon after passage of the 1980 law, NRC issued the first comprehensive set of criteria for regulating LLW disposal facilities. Contained in Title 10 of the Code of Federal Regulations, Part 61 (10 CFR 61), the criteria cover procedures and performance objectives to guide states in licensing LLW facilities.

The NRC's requirements, based on insights gained from past practices and current experience at existing sites, are significantly more stringent than those that applied in the 1960s and 1970s. Despite problems at some disposal sites in the past, most experts believe shallow land burial continues to be a safe and viable approach to LLW disposal if sites are chosen with careful consideration of underlying geology and operated according to strict procedures. Political developments, however, are forcing serious consideration of enhanced burial techniques (incorporating engineered structures and barriers) and alternatives to shallow land burial.

Although the licensing guidelines contained in 10 CFR 61 apply to any land disposal method, specific technical requirements assumed shallow land burial. NRC is now assessing the need for technical criteria for other disposal or interim storage techniques, such as concrete bunkers or engineered structures above ground.

At least 31 states have ratified regional compacts, but the lack of a single new disposal site in the firm planning stage one year before the exclusion deadline



reflects the continuing negotiations among compact states and nonmembers alike over who will join the host state ranks. According to experts, it takes from five to six years to select, license, and begin full operation of a disposal site.

Four regional compacts are awaiting congressional approval; three of these—covering the Northwest, Southeast, and Rocky Mountains—would use the existing commercial sites in Washington, South Carolina, and Nevada, respectively. But the Southeast compact provides for continued use of the Barnwell site only through 1992, and a search is under way for a site in Colorado to eventually replace the Beatty, Nevada, facility.

The fourth compact, among five states in the central United States, has begun a site selection process.

Five other regions—including part of the Northeast, the Midwest, Central Midwest, and Western states—have draft agreements in various stages of state approval. Pennsylvania has agreed to host a disposal site in a compact agreement with West Virginia, Maryland, and Delaware. A New York State proposal to establish an interim, monitored storage facility in New York awaits legislative and executive approval. But in Massachusetts, a major LLW-producing state, voters have retained a veto right over possible disposal sites, clouding efforts to make agreements with other states with continued uncertainty.

Elsewhere, California and Arizona have proposed to join in a two-state Western compact, but the agreement, which calls for California to host an LLW disposal site, also awaits approval by that state's legislature. Texas, perhaps further along the road to a new LLW site than any other state or compact group, decided early on to establish its own LLW disposal authority and is currently narrowing the search for a suitable site.

Based on available information, it appears that states accounting for more than half of the volume and nearly three-quarters of the radioactivity of the nation's LLW may not be ready to assume their responsibilities by next January's exclusion deadline. There are indications that these states may push for a congressional amendment to the 1980 act that contains a mechanism for providing disposal capacity beyond the 1986 deadline while compacts proceed with establishing their own facilities.

Implications for utilities

Although the problems of providing new sites for disposal are being worked out on the state and federal level, most producers of LLW find themselves in the role of observers of the unfolding institutional drama. For the most part, utilities are not actively involved in the compact negotiations or in the site selection process, although the outcome of these negotiations will directly affect future disposal costs and related technologic choices.

Despite the uncertainty and political volatility of the site availability issue, utilities and other significant generators of LLW must nonetheless continue planning for management and ultimate disposal of waste. For waste producers, the cost of available options is the driving force behind strategic planning for LLW.

Thus, regardless of where the waste drums are eventually shipped for disposal or stored in the meantime, utilities have for many years sought to minimize the volume of LLW requiring disposal, both through operational practices that limit the amount produced and techniques such as compaction and incineration that further reduce waste volume. In addition, most utilities are now planning to add on-site storage facilities at nuclear plants to handle LLW until adequate commercial burial capacity is available.

EPRI has assisted the industry with surveys of utility experience with LLW volume reduction systems and plans for on-site storage. A comprehensive data base has been established for characterizing in detail the quantity and type of waste from various nuclear plant sources to aid utilities in managing LLW programs.

The Institute has developed a computer code for assessing a wide range of volume reduction equipment under various economic conditions and scenarios. EPRI studies have also provided utilities with technical performance criteria for evaluating LLW solidification technologies and containers. And new techniques are being developed for accurately determining the radionuclide content of LLW.

Volume reduction

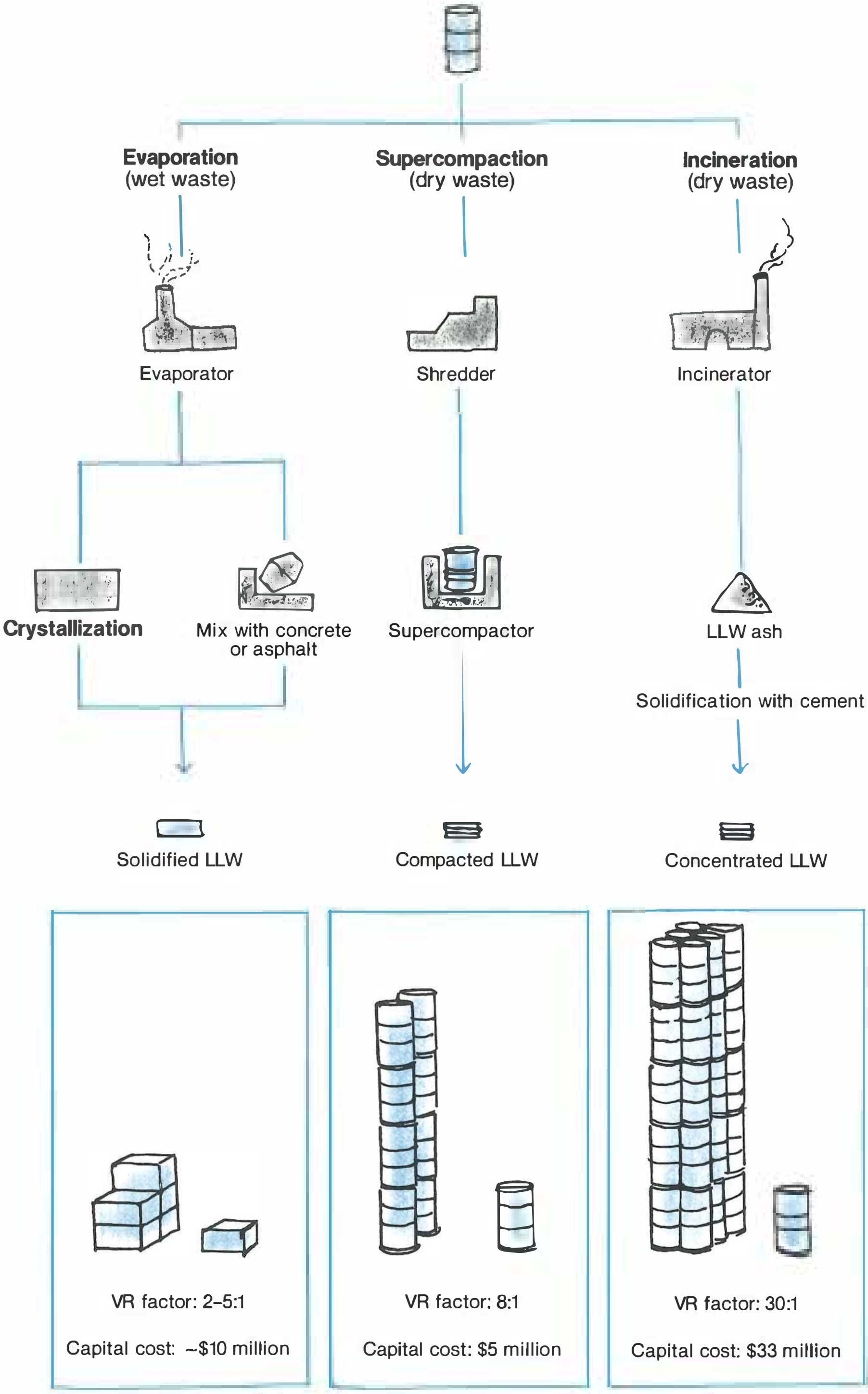
In response to rapidly increasing disposal costs and uncertain availability of commercial disposal capacity, many nuclear utilities are considering upgrading radwaste volume reduction (VR) systems and on-site storage facilities. Under EPRI sponsorship, Burns and Roe, Inc., surveyed nuclear utilities around the country to determine the influence of site-specific and regional factors on utility plans in this regard. Results characterize typical nuclear utility planning as an aid to other utilities that are about to commence similar planning. A report on the project includes design details of 22 on-site storage facilities and sketches of 14 such structures as well as drawings of advanced VR facilities.

Of 77 nuclear plants originally targeted for the survey, information was subsequently gathered from 54. Results indicated that as of late 1983, 36 storage facilities were planned or under construction. Reinforced concrete structures were the favored design for on-site storage, although some facilities feature simple metal-sided warehouse structures. The majority of the facilities were sized to provide storage capacity for five years at an average LLW generation rate of 12,000 ft^3 (340 m^3) per plant over the period for pressurized water reactors (PWRs) and 23,000 ft^3 (650 m^3) per unit for BWR plants.

As for VR systems, the survey indicated 27 nuclear plants expressed interest in planning for some type of advanced VR equipment, such as super-

Volume Reduction Options

In response to rising burial and transportation costs, most utilities are pursuing a combination of LLW packaging options that reduce waste volume to the minimum practical level. A wide range of volume reduction (VR) equipment is now available for this purpose. Leading candidates appear to be supercompaction systems for dry waste and evaporation/solidification systems for liquid wastes. Incineration is another option for dry waste; although it has been little used commercially in this country because of political and regulatory concerns, extensive experience with incineration has been gained at many of the national laboratories.



compaction or incineration; about 35 nuclear plants had already ordered or installed advanced VR systems as retrofits or new facilities.

"Although most nuclear plants can be expected to go ahead with plans to build on-site storage facilities, their future actions are not so apparent with respect to VR installations," notes Naughton.

"VR facilities can be an expensive alternative, with costs ranging $10–$50 million per plant. Utilities will most likely pursue low-cost VR options in the near term. But if burial costs are dramatically increased by state compact decisions, maximum VR capability could become a necessity for all plants," he adds. Naughton points out that recent pricing changes at current commercial disposal sites that include a curie surcharge on the radioactive content of LLW tend to reduce the economic benefit of volume reduction.

Yet there are significant commitments to advanced VR systems: Consumers Power Co. has installed a bitumen (asphalt) solidification system made by WasteChem Corp. at its Palisades plant; similar systems have been ordered for at least five other plants. Commonwealth Edison Co. has installed Aerojet Energy Conversion Corp.'s fluidized-bed incinerator-dryer system at its recently completed Byron plant. Duke Power Co. is building a new VR facility at its Oconee nuclear station that includes the Aerojet incinerator system, a crystallizer for liquid wastes made by HPD, Inc., and Stock Equipment Co.'s cement-based solidification system.

"These are strong statements in support of advanced volume reduction," adds Naughton, "especially considering that the Oconee plant is in South Carolina." Under a contract with Sargent & Lundy, EPRI plans to document installation and initial operation of the VR incinerator system at Byron, now in preoperational testing.

Incineration of LLW is a VR option for dry material, ion exchange resins, and contaminated oil. It has been widely and successfully used at government and industrial facilities in this country and at many nuclear plants in Europe and Japan. At least eight Aerojet incinerator-dryer systems have been ordered for U.S. nuclear plants, but most utilities are awaiting a clearer picture of the long-range economics of incinerator systems before making firm commitments.

An EPRI-funded survey performed by Gilbert Associates, Inc., gathered detailed information on the design and operation of 26 LLW incinerator facilities and development prototypes in Canada, Europe, Japan, and the United States. The project assessed the licensability of incinerator types most likely to be used at U.S. plants.

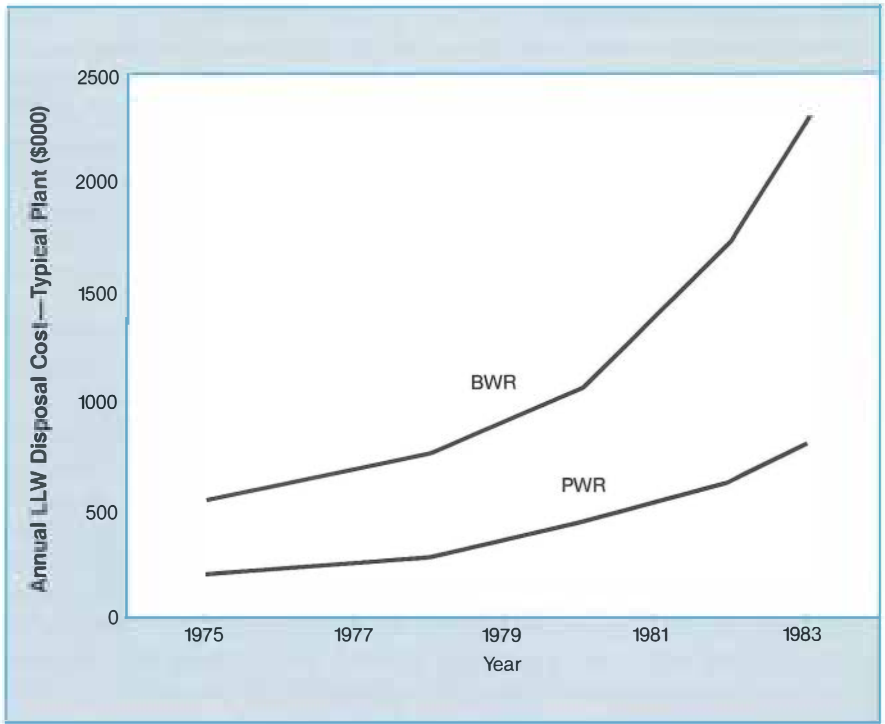
The study found LLW incinerator technology to be well established on the basis of 40 years' experience in which some 4000 tons of material have been processed. Incinerators, which reduce bulk material by a factor of 30 or more of its original volume to produce a concentrated LLW ash product, can be safely and reliably operated; high-efficiency offgas filtration systems keep gaseous radioactive effluent releases well below regulatory limits, the survey indicated.

Choosing among options

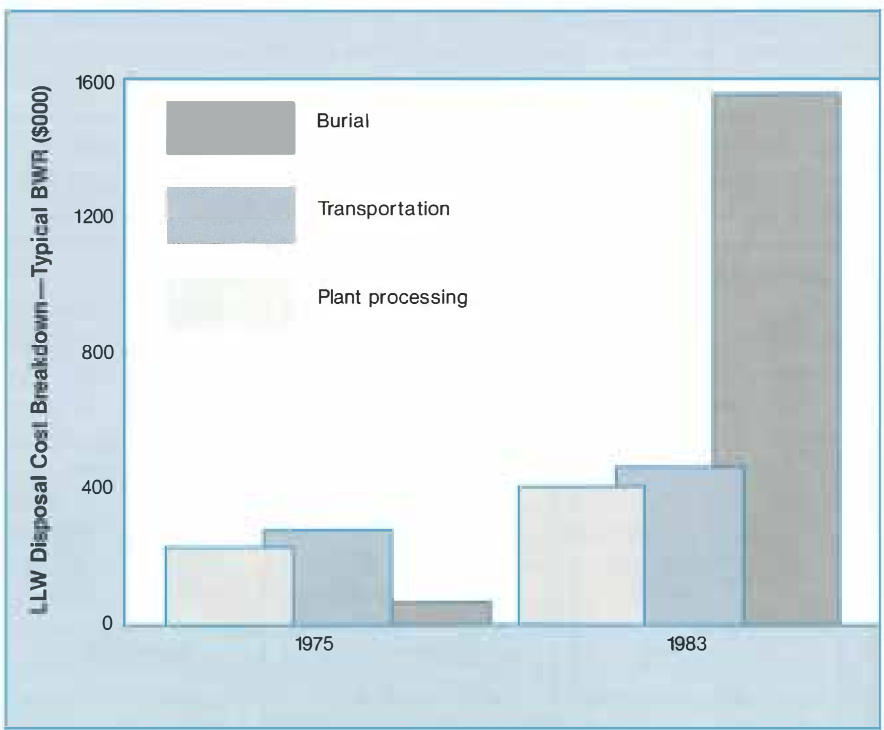
Perhaps one of the most difficult tasks in utility LLW management planning involves assessing the comparative economics of various VR equipment and storage options under widely varying assumptions. Thorough assessment of a single VR option may require hundreds of inputs to complex, tedious calculations.

To aid utilities in these assessments, EPRI funded a project by Burns and Roe and The Analytic Sciences Corp. to compare the long-range economics of various VR technologies and to develop a model that could easily and quickly analyze a wide range of technologies and economic factors. The resulting computer code, VRTECH, has emerged as a powerful tool for such evaluations.

VRTECH, available through the Elec-



Cost of LLW disposal has risen dramatically in the last decade, primarily because of higher burial costs resulting from increased charges at disposal sites. The overall increase has been particularly acute for BWR plants, which produce an average 50% more LLW than do PWRs.



tric Power Software Center, has calculated the disposal costs of over 3000 separate cases and configurations in only three minutes of computer time. In a generic analysis of VR systems, the code was used to explore economic sensitivities by calculating costs under 40,000 different combinations of equipment, waste generation rates, storage options, burial prices, and other parameters.

Highlights of project results include the conclusions that the most important factors in VR economics are the rate of LLW generation and the rate of escalation in burial prices. VR is generally most cost-effective at BWR plants—which produce an average of 50% more LLW than PWRs—and can result in significant savings in transportation, operation, and storage costs. Calculations indicate that VR can yield a net saving today despite higher waste activity charges at commercial sites because the reduction in volume charges exceeds the increase in curie surcharges.

One utility that has already used VRTECH to realize a substantial saving in LLW management is the Tennessee Valley Authority. The federal utility had plans dating from 1980 that called for onsite storage and incineration of radwaste at its Browns Ferry, Sequoyah, and Watts Bar nuclear plants, and it was approaching a critical decision point on the purchase of VR equipment.

Faced with an urgent need to reanalyze its options given recent changes in costs, technologies, and legislation, TVA worked with Burns and Roe and Analytic Sciences to use VRTECH for evaluating VR alternatives including incinerators, supercompactors, and solidification systems. With VRTECH, TVA was able to organize a tremendous amount of site-specific information and compare it with individual and collective plant waste streams as a basis for decision making.

As a result TVA changed its approach to LLW handling; VRTECH calculations identified an optimal combination of VR equipment requiring minimal capital costs that still provided significant waste volume reduction. "Using the EPRI approach and computer program, we identified a radwaste management program with a potential net saving of $137 million over the remaining life of our nuclear plants," says TVA's Douglas Michlink.

Other approaches

In addition to VR equipment for minimizing LLW disposal volume, specific operating practices at nuclear plants can help utilities limit the amount of LLW produced. Under EPRI contract, Gilbert Associates used an extensive data base on various LLW categories from two-thirds of the nation's operating nuclear plants to analyze waste generation experience for insights on key operating factors that influence the amount of waste generated.

From a wealth of information, it was found, for example, that BWRs can reduce wet waste volume by about 40% simply by disposing of condensate demineralizer resins rather than regenerating this material. In addition, PWRs that convert from concentrator to demineralizer processing of wet waste can reduce this source of LLW by as much as 75%. Overall, some 100 waste-minimization techniques were documented. Many plants have successfully implemented dry waste minimization programs, resulting in LLW reductions of 20–60%, the study found.

Utilities can also reduce burial costs of radwaste shipments through more-accurate assay techniques for identifying the amounts of specific isotopes contained in waste drums. Recent radioactivity surcharges at commercial disposal sites are an incentive for utilities to define as precisely as possible the isotopic content of shipments.

One approach to waste assay under development employs direct gamma scanning of the waste container. The presence and amount of gamma-emitting isotopes can be correlated with other important radionuclides that would otherwise require direct sampling of waste to quantify; the technique thus provides an accurate means of determining the full spectrum of radioactivity in a waste container. Virginia Electric Power Co. successfully applied this technique on LLW resin from its Surry nuclear plant. EPRI is continuing development of gamma-scanning technology.

The institutional challenge

Technology for safe, effective treatment and disposal of low-level radioactive waste has been in hand for many years. The problem of LLW is more of a political and institutional nature. Utilities and other waste producers are already under strong economic incentives to minimize waste and to reduce the volume of material requiring disposal. Now, in addition, they must plan long-range strategies for LLW management despite continuing, major uncertainties over the availability of disposal site capacity.

The prospects of these uncertainties being neatly resolved in the near-term are probably not favorable. Until they are resolved, however, there will continue to be compelling cost incentives to reduce other areas of uncertainty as much as possible. EPRI has made significant contributions in this regard and will continue to provide utilities with technical and planning assistance for informed decision making. ■

Further reading

Long-Term Low-Level Radwaste Volume Reduction Strategies, Vols. 1–5. Final report for RP1557-13, prepared by The Analytic Sciences Corp., November 1984. EPRI NP-3763.

On-Site Storage of Low-Level Radwaste: A Survey. Final report for TPS 82-657, prepared by Burns and Roe, Inc., July 1984. EPRI NP-3617.

U.S. Nuclear Regulatory Commission. *Proceedings of the State Workshop on Shallow Land Burial and Alternative Disposal Concepts*. Held at Bethesda, Maryland, May 2–3, 1984. NUREG/CP-0055

Radwaste Incinerator Experience. Final report for RP1557-4, prepared by Gilbert Associates, Inc., October 1983. EPRI NP-3250.

U.S. Department of Energy. *Understanding Low-Level Radioactive Waste*. Prepared by EG&G Idaho, Inc., October 1983. DOE/LLW-2.

This article was written by Taylor Moore. Technical background information was provided by Michael Naughton, Nuclear Power Division.

Florida Utilities Use REEPS to Evaluate Conservation Programs

When the Florida Public Service Commission was authorized to mandate energy conservation goals, the state's utilities responded with a number of comprehensive demand-side conservation programs. A group of 11 Florida utilities agreed to test an EPRI code, the residential end-use energy planning system (REEPS), in evaluating alternative conservation programs. Using the code, the utilities developed a base case scenario for Florida as a whole, together with specific maximum cost-effective conservation scenarios based on customer rebates. Florida Power & Light Co., for example, verified the cost-effectiveness of its existing rebate program, for an estimated savings of about $3 million a year. ■ *EPRI Contact: Steven Braithwait (415) 855-2606*

Water Supply Directory Speeds Siting Analysis

The comprehensive *Water Supply Computerized Information Directory* has been made available by EPRI to help utilities ensure a sufficient supply of cooling water at potential power plant sites. Developed under EPRI sponsorship by the University of Arizona and updated and maintained by the U.S. Geological Survey, the directory is a guide both to water data bases and to national and regional organizations dealing with water supply. Its use can save utilities considerable time and money, compared with surveying the multitude of water information sources on their own. For example, the Los Angeles Dept. of Water & Power (LADWP) estimates that using this directory will save $70,000 of staff time and travel in determining water supplies for two new projects. "This directory is an invaluable tool to any large utility involved in power plant siting," says Frank Salas of LADWP. ■ *EPRI Contact: Edward Altouney (415) 855-2626*

X-Ray Analyzer for PCB Screening

A compact, easy-to-use X-ray fluorescence instrument—the MESA 200 analyzer—has been developed under EPRI sponsorship for use in screening transformer oil for PCB contamination. Available from Horiba Instruments, Inc., the analyzer provides an accurate measurement of total chlorine concentrations from 0 to 1000 ppm. No special operator skills or interpretations are needed to run the MESA 200, and no sample preparation is required. Demonstrated costs are less than $3 per sample. The instrument has been designed for easy transportation and rugged field use. It uses a low-energy, long-life X-ray tube and requires no nuclear certification. ■ *EPRI Contact: Vasu Tahiliani (415) 855-2315*

Reference Manual Improves Quality of Econometric Data

The accuracy of load-forecasting models is limited by the quality and type of data used, but verification of these data has often been beyond local capabilities. Puget Sound Power & Light Co. (PSPL) validated data for end-use models by working with Mathematical Sciences Northwest, Inc., as an EPRI demonstration utility. This project resulted in publication of a reference manual of data sources that other utilities can now use to verify their own load-forecasting data. More than 100 variables were considered in the evaluation, and comparisons were made between the models and data used by PSPL and five other utilities representing different regional and local characteristics. As a result of the study, according to Paul Ahern of PSPL, we now know which data are reliable, accurate, and consistent.
■ *EPRI Contact: Ahmad Faruqui (415) 855-2630*

Volume Reduction Cuts Costs of Radwaste Management

The Tennessee Valley Authority (TVA), like many other nuclear utilities, has recently been reassessing its program for managing low-level radioactive waste. This reassessment has come as the result of steadily increasing disposal costs and enactment of the Low-Level Waste Policy Act, which comes into effect in 1986. For TVA, a critical decision involved whether to purchase volume reduction (VR) equipment as part of its radwaste management program. Using a computer program (VRTECH) developed for EPRI by Burns & Roe, Inc., and The Analytic Science Corp., TVA evaluated site-specific costs and benefits of various VR alternatives and selected a combination of technologies that represent a potential net saving of $137 million over the life of the nuclear plants involved. ■ *EPRI Contact: Michael Naughton (415) 855-2775*

UNIRAM Code Spots Components Critical to Unit Availability

The UNIRAM software package, designed to help the electric power industry increase availability levels, has now been licensed for use to 38 utilities nationwide. The recently revised computer code functions by modeling and evaluating a generating unit as a set of components, allowing utilities to spot the weak links that often lead to forced outages. The software uses such plant data as mean time between failures and mean downtime to model a unit's reliability, availability, and maintainability (RAM) characteristics. The code's ability to perform sensitivity analyses allows utilities to rank the criticality of components. In one analysis, for example, it was found that one-third of the components accounted for almost all of the forced outages and deratings. Other applications for UNIRAM include analyses of plant life extension, maintenance evaluation, and economic trade-off studies. Users find the code's flexibility especially attractive as it can provide useful data with limited input. ■ *EPRI Contact: Jerome Weiss (415) 855-2495*

Sodium Carbonate Boosts Precipitator Performance at Cleco

A new sodium conditioning system is making hot-side electrostatic precipitation a success story for Central Louisiana Electric Co. (Cleco). Like many other utilities, Cleco is burning low-sulfur coal at its new Rodemacher Station Unit 2 plant. To meet particulate emission standards with this coal, the electrostatic precipitator was installed on the hot side of the air preheater, but the station still failed to meet compliance requirements. Earlier studies funded by EPRI pointed to sodium depletion in the fly ash layer as the problem and sodium additives to the coal stream as the solution. But those earlier tests used only one type of coal. Together, EPRI and Cleco reviewed the earlier data, and Cleco decided to install a sodium carbonate coal-conditioning system. The system has since proved successful in achieving compliance, and at the same time it has saved Cleco $3.4 million per year in stack cleaning costs and replacement power costs during cleaning outages. ■ *EPRI Contact: Ralph Altman (615) 899-0072*

LADWP Assesses Construction Impact on Rural Community

As part of its Environmental Impact Statement process for a major power plant, the Los Angeles Dept. of Water & Power (LADWP) wanted to establish a plan to reduce the socioeconomic impacts on the small communities involved. The 1500-MW White Pine power project was to be located 45 miles (72 km) north of Ely, Nevada, and LADWP needed data from similar sites to determine how the rural mining area would be affected by the new plant. To find such data, the utility turned to a two-year study of power plant impacts conducted for EPRI by the Denver Research Institute. Together, LADWP and local officials reviewed and discussed the case studies involving socioeconomic characteristics similar to White Pine country. Based on these discussions, the utility was then able to develop an alleviation plan that was universally accepted by the local communities. ■ *EPRI Contact: Sherman Feher (415) 855-2838 or Ronald Wyzga (415) 855-2577*

Penelec and NYSEC Optimize Coal-Cleaning Design at CCTF

When Pennsylvania Electric Co. (Penelec) and New York State Electric and Gas Corp. (NYSEG) chose physical coal cleaning as the primary emission control technology for Unit 3 of their jointly owned Homer City generating station, they needed some way to optimize both the cleaning process and the selection of coal. To conduct the necessary research, the two utilities used the EPRI Coal Cleaning Test Facility (CCTF), located in Homer City, Pennsylvania—a demonstration-scale plant capable of testing different coal-cleaning flowsheet configurations and simulating commercial plant conditions. Tests at CCTF provided Penelec and NYSEG with data on the cleanability of candidate coal supplies for their power plant, together with information they could use in the design, equipment selection, and operation of their own coal-cleaning facility. The utilities estimate the use of CCTF will save them $68.7 million over the life of their new plant. ■ *EPRI Contact: Clark Harrison (412) 856-7120*

New Leader for Rural Electrics

The new executive vice president of NRECA discusses the challenges rural electric cooperatives are facing in the competitive 1980s.

"I am not an engineer, nor a lawyer, nor a scientist. My background is politics, and I have been politically active all my life. I came to NRECA with some biases, one of which is a belief that most important decisions are made politically. The cooperatives must always be involved in the political process because that is where public policy is set."

The speaker is Bob Bergland, the new executive vice president and general manager of the National Rural Electric Cooperative Association (NRECA). Bergland has strong opinions on the role and effectiveness of politics in the utility industry; however, his statement tells only part of the story of why he is particularly well suited for leading a national association of 1000 rural electric systems.

Bergland was raised on a family farm in the northwest corner of Minnesota. His father not only was one of the founders of the local utility, Roseau Electric Cooperative, but also served on its board of directors for 30 years. After graduating from the School of Agriculture at the University of Minnesota, Bergland bought a farm in his home county that is now run by his daughter and son-in-law. Thus, family tradition and a career in politics equips Bergland with an interesting combination: a farmer's commitment to the land and to rural electrification and a politician's inside view of how Washington works.

Bergland's public service began in 1963, when he was appointed Midwest director of the Department of Agriculture's Stabilization and Conservation Service. "After serving as Midwest director for the USDA, I decided to run for Congress in 1968 to represent my home district, Minnesota's 7th district, and I lost." But Bergland ran again in 1970 and won, serving in the House of Representatives for the next seven years. Then in 1977 President Carter asked Bergland to serve on his cabinet as secretary of agriculture, and he headed USDA for the next four years. "I originally turned down the USDA job because I was happy serving my district in the House. But Hubert Humphrey, my mentor in Congress, called me and said that if President Carter needed me at Agriculture, I must help him. So I did."

With the change in administrations in 1981, Bergland left Washington to work for Farmland World Trade, a subsidiary of Farmland Industries, where he helped develop agricultural trade markets in such countries as China, Mexico, and some of the developing nations. Succeeding Robert Partridge, who retired last year, Bergland stepped into the NRECA general manager's position last April. He feels he has two important goals to accomplish in his new position. The first is to assess and adequately respond to the changes and developments taking place in rural America and within the rural electric cooperative program, and the second is to continue NRECA's strong political presence in Washington.

Rural Electrics Today

Bergland is aware that the constituency of rural electric cooperatives is different from the days when his father was active in the cooperative in Bergland's hometown of Roseau. "We are seeing substantial changes in the rural electric utility business. Rural cooperatives were started in 1935 to bring electricity to the 6 million farms then in the United States. There are now 1051 rural electric systems in 46 states and they serve just under 10 million meters, more than 25 million people. Of course, the cooperative membership has changed since 1935. Of our current 10 million member-owners, only 1 million are farming commercially full-time. Another one million members, who farm part-time, are sometimes called hobby farmers because they do not depend on farming for their livelihood. There are probably 8 million members on the rural electric lines that do not farm at all. These are rural residents, of course, and we need to find out more about these people. One of my goals, therefore, is to develop and guide programs to help understand and assist this diverse consumer membership."

Bergland

Bergland also believes that there will probably be few new jobs in farming, and so rural communities have to strengthen the businesses that already exist in their areas. The rural electric cooperative can be a leader in this effort by helping to encourage more economic diversity in rural areas.

NRECA will be building on its traditional rural development efforts with a new marketing strategy that emphasizes reliable and community-responsive rural electric service to attract businesses to rural areas. "The utility business is moving from a rather sheltered life to the more turbulent world of the competitive marketplace. The cooperatives are not exempt from this, and we have to be better equipped to deal with competing forces, not only in terms of competing fuels but also with such new techniques as time-of-day pricing and new creative rate structures. Utilities have to encourage the use of electricity in the most efficient way possible," Bergland explains.

Another way for cooperatives to increase economic diversity in the community is through the expansion of the utility's own services. For example, more rural electrics are becoming involved in the telecommunications business.

"Cable television people tell me that it isn't economic to string cable with fewer than 15 consumers per mile of line. That means that most rural families will not have good television programming. So we have a committee here at NRECA working with the National Rural Utilities Cooperative Finance Corp. [CFC] to look into the benefits and feasibility of rural electric cooperatives' assisting in the mission of providing home satellite television service.

"Two cooperatives already have such a program under way. The NRECA–CFC study will take a look at the full range of benefits that can be realized through telecommunications technology, to both the cooperative and the consumer. I think it does make sense, because cooperatives have a history of providing reliable service to their communities," Bergland says.

Rural Electrics and Research

As a national service organization, NRECA's purpose is to represent and guide its membership on important issues, whether arguing against administration budget cuts on Capitol Hill or preparing detailed reports on the future of telecommunications. One area where Bergland hopes NRECA and its member systems will move ahead is in an increased commitment to research and development. "Research is vital," he emphasizes. "There is absolutely no way that our industry or nation can remain competitive or thrive without solid research. This is a fundamental truth and nonnegotiable."

Bergland explains that EPRI's research has already helped the rural electrics in many ways. The cooperatives have a great interest in the new coal technologies that EPRI is pursuing, such as fluidized-bed combustion and coal gasification. The rural electrics also have a great deal of interest in research into small-scale and modular power plant construction. "Most utilities cannot afford to build a new 1000-MW plant; it is just too expensive. What we probably need is to construct small plants that can be added to incrementally as the demand for electricity grows. I am glad to see that EPRI has a research program studying the feasibility of modular plant construction."

Bergland continues by noting that one area of research of great importance to rural electrics involves greater efficiencies in distribution. "One of EPRI's recent developments that we feel has great potential for rural electrics is the new low-core-loss transformer, which could save substantial amounts of energy. We are especially pleased that EPRI has allocated 200 of these new transformers for field testing by rural electric cooperatives."

Political Challenges

The fact that Bergland views himself as a political creature will be useful to NRECA in the current legislative session. NRECA has found itself in a battle with the Reagan administration over the future of the Rural Electrification Administration (REA). This agency of the Department of Agriculture was created in 1935 to finance electric services in rural areas. Later, it was expanded to include loans to rural telephone systems. Specifically, the Rural Electrification Act of 1936 established REA as a lending agency to develop a permanent program of rural electrification. The act has been amended several times.

At present, REA loans to distribution systems are long-term, interest-bearing loans, made from a revolving fund, with interest accruing at a standard rate of 5% or a rarely available special rate of 2% for qualifying cooperatives. REA requires that the standard loans be supplemented by nonfederal capital, usually in a ratio of 30% private to 70% REA funds. REA also guarantees loans to generation and transmission cooperatives. Most of these loans are made by the Federal Financing Bank at the cost of money to the Treasury plus one-eighth of 1%.

REA electric loans are made with preference to nonprofit and cooperative associations and are used to finance the construction of electric utility systems. About 93% of REA-financed electric systems are cooperatives, which means they are owned and controlled by the consumer-members.

The Reagan administration's budget analysts, who emphasize free market and private sector competition, have frowned on the REA low-interest loans. In fact, as Bergland explains, it is quite possible that the Office of Management and Budget will suggest to the president that REA be abolished as another move to cut federal spending.

Bergland explains why REA is so important to the rural electric cooperatives. "One reason why we are so adamant about maintaining REA's presence is that the rural electrics have unique problems as utilities. The 1000 rural electric systems own and maintain more than 40% of the nation's miles of distribution lines, covering about 75% of the country's land mass, to serve only 10% of the population. On the average there are fewer than five consumers per mile of line.

"If REA is dismantled, with government support withdrawn from rural electrics, the cooperatives would face substantial rate increases, which would strain the rural areas served by these cooperatives. The weaker of them would go out of business—there isn't any question of that. And if the local electric cooperative goes out of business, there isn't any other utility who is going to come in and serve these remote rural customers. I believe that possibly 250 distribution cooperatives will fail if REA's help is cut off. There must be a federal presence to help these cooperatives survive. This is true with a lot of the other services in the rural areas that are assisted by federal programs, such as the mail service, farm-to-market roads, and telephones."

There is a fundamental national philosophy behind the need to keep REA operative, Bergland emphasizes. "A basic tenet of Thomas Jefferson's view of our nation was that citizens should be encouraged to live on the land and buy it as their own. Jefferson was, of course, reacting to the European tradition where the gentry owned the land and leased it to tenant farmers. But the United States has always encouraged people to live on farms and to settle new areas. The catch is that bringing services to these remote areas is expensive and some federal support is vital for these essential services. This is why the loan program at REA is so necessary—it offers people the opportunity to live comfortably in rural communities, thereby fulfilling one of the original principles on which our country was founded."

Another issue related to REA that Bergland and NRECA may have to face is the possible abolishment of REA's engineering standards division. This division provides and enforces standards for the quality of construction of rural electric systems and also assists REA borrowers with technical problems. Because REA set up these standards at the beginning of rural cooperative development and made the standards a requirement of the loan contract, each cooperative system is constructed in the same way. "The REA standards have made it easy for engineers to work on various cooperative systems because all the designs and specifications are the same," Bergland notes. "It would be a grave mistake to abolish the standards program, and we cannot let it happen. Of course, eliminating the standards program is just one way to begin to reduce the overall REA program. It demonstrates the administration's lack of commitment to federal energy development. This brings me to another point regarding the current administration that worries me: the lack of a national energy policy."

Bergland believes that the administration is painting too rosy a picture of the nation's energy future. The fact that the price of oil has recently dropped does not mean that it will always stay low. "In fact, for the past 11 years we have been on a downhill slide in proven oil reserves; we are burning more oil than newly discovered sources can provide, and we are bound to run out sometime."

Bergland is concerned that the country will not see a national energy program emerge during the current administration, so he argues for a national electricity policy. "I do feel strongly that the nation has to start thinking about electricity on a national level. There has to be a coherent nuclear power policy, as well as direction given on the role of new energy technologies." The other reason he sees for a national electricity policy is that demand for electricity will continue to grow, particularly with new electronic devices entering the commercial market.

Bergland realizes, however, that the electric utility industry is one of the most diverse industries in the nation. "One of the major deterrents to an idea such as a national electricity strategy is that the country's electricity is currently provided by 1000 rural electric utilities, 2200 municipals, and 221 investor-owned companies. It is very difficult to get all these different types of utilities to agree. But I believe that we are now seeing more cooperation among electric utilities in the form of power pools or joint action agencies."

Bergland also believes that the nation's electricity must now be thought of as a national commodity and should be viewed as a national pool of power. "I am not sure if the answer would be a better grid system or better regional interties, but I do know that some regions of the country have a surplus of power while others, possibly right next door, have a shortage. With a national electricity policy, the question of whether one region should build a new power plant when its neighbor has surplus power could be handled. As it stands today there is no national forum where these issues can be discussed, and we do need one. It might take 10 years to develop such a forum, so we should get on with it." If and when such a forum takes place, Bergland is sure to be in the thick of it, arguing the views of rural electric cooperatives. ■

This article was written by Christine Lawrence, Washington Office.

Board Completes Effectiveness Review

A review by EPRI's Board of Directors gives the Institute high marks on its value to the utility industry.

EPRI and its staff have earned an excellent reputation and are contributing significant R&D results to meet present and future needs of electric utilities and their customers, according to an effectiveness review conducted by EPRI's Board of Directors in 1984. A report on the review—the second to be conducted within 11 years—was discussed by the Board at its December meeting in Palo Alto.

Among the Institute's accomplishments, the review found that member utilities have used more than 300 products developed by EPRI. Just the initial use of these products, excluding any subsequent uses, has saved the utilities involved more than $412 million a year.

At the same time, however, the review also found that two pervasive challenges face both the Institute and its utility members. A paramount challenge is that of gaining a wider and deeper commitment to R&D from the industry. The review asserts that the electric utility industry is barely meeting its current technology challenges. More long-term and exploratory research is also cited by the Board's review as an important need.

Looking to the future, the effectiveness review found that EPRI must emphasize technology that enhances the end-use value of electricity. The review says the electric power industry is entering a new era, one in which the work of electricity must be of the highest possible economic value to utility customers and to the nation. It notes that EPRI and its members must work to achieve fuller utilization of R&D results. Improved technology transfer, in all its forms, is required.

In addition to emphasizing end-use research, the review also identified a number of significantly unfunded or underfunded R&D areas. These include extending the operating life of power plants, advancing the economic availability of coal-fueled generation systems, and seeking cheaper methods of moving power over transmission lines for greater distances.

According to an independent survey conducted as part of the review, EPRI members and nonmembers alike believe the electric utility industry should commit a higher proportion of its revenues to the Institute. Members reported that in 1983 they spent 0.6% of their gross electricity revenues on R&D, which included their participation in EPRI. Asked their opinions on an appropriate level of R&D funding, the average of responses indicated 1.3% of gross revenues—the same percentage as that spent by the telecommunications industry. ■

Photovoltaics Preproduction Facility Approved

A $10 million project to develop a pilot manufacturing process for high-concentration photovoltaic (PV) cells was approved by the Institute's Board of Directors at its December meeting. EPRI will fund $5 million of the amount and is seeking support from member utilities for the other $5 million to conduct operations over 42 months. The funds will be used to lease space in a building, purchase equipment, and conduct research to establish the cell manufacturing process.

"This facility is essential in developing a thorough understanding of the product and quality control aspects of the cell manufacturing processes," reports John Cummings, director of the Renewable Resource Systems Department. The preproduction facility approved by the Board is the next step in continuing EPRI-supported PV research, which has been under way since 1976 at Stanford University.

Work so far has resulted in a PV device developed specifically to meet performance and economic requirements needed by utilities for generating bulk power. Prototypes indicate a potential efficiency of over 25% in converting concentrated sunlight into electricity, which is very high in comparison with earlier devices. The cell is of special interest to utilities in high direct sunshine regions, such as the southwestern United States.

The manufacturing of high-concentration PVs is unique because it uses integrated circuit manufacturing technology developed in the semiconductor industry. This process technology promises a high degree of quality control. "We need to proceed into preproduction processing research to show that the cell can be manufactured with satisfactory efficiency at high yields and that it will perform as designed when integrated into PV arrays," explained Cummings. "Operations in this facility will provide a basis for transferring the PV research to a marketable product."

High-concentration PV systems have been the major focus of EPRI's Solar Program for several years. Successful completion of this research, along with parallel advances in module development, is expected to lay the foundation for pilot plants in the late 1980s. This will be followed by commercial production, with the installation and operation of several hundred megawatts of PV power by the mid 1990s. Contracts for the facility development are expected to be issued this spring so that limited operation can begin by the end of 1985. ■

Chinese Nuclear Delegation Visits EPRI

A six-member delegation of nuclear engineers from the People's Republic of China visited EPRI recently for a briefing on R&D programs in low-level radioactive waste (LLW). The December visit was part of a two-week tour of U.S. nuclear plants and radwaste facilities organized by the American Nuclear Society in cooperation with the Chinese Nuclear Society.

Wang Dao Yuan, chief engineer for waste management at the Beijing Institute of Nuclear Engineering, led the delegation. The group's other members were Li Xue Qun of the Ministry of Nuclear Industry's Bureau of Safety, Protection, and Health; Yu Cheng Ze of the Institute of Atomic Energy; Zhou Zi Rong of the Institute of Radiation and Protection; Li Zheng De of the Chinese Nuclear Information Center; and Yang Li Ji, also from the Beijing Institute of Nuclear Engineering.

John Taylor, EPRI vice president, and Don Rubio, director of the Nuclear Power Division's Engineering and Operations Department, welcomed the group. Robert Shaw and Michael Naughton presented an overview on the status of LLW disposal in the United States and EPRI's related research efforts.

"The People's Republic is planning for the introduction of nuclear power for generating electricity and wants to establish criteria for waste management ahead of the time we anticipate handling significant quantities of nuclear waste," said Yang Li Ji. He added that China expects to begin a disposal site selection process this year.

According to Wang Dao Yuan, China has conducted experiments with waste solidification processes and plans to build some type of LLW solidification plant; waste generated in nuclear R&D and medical applications now is stored for later disposal. ■

EPRI Studies Effects of Electromagnetic Fields

EPRI is one of two U.S. organizations now funding epidemiologic research into the possibility of health effects resulting from human exposure to electromagnetic fields (EMF). The study (RP2378-9) is designed to find whether persons with leukemia were exposed to EMF on their jobs more often than would be expected on the basis of chance alone.

From among its more than one million employees, the American Telephone and Telegraph Co. is providing EPRI researchers with the records of 200 patients who have been diagnosed during recent years as having leukemia. AT&T was chosen to assist EPRI in its investigation of linemen because of its own interest in the research and because the company has kept extensive and thorough employee health records. Johns Hopkins School of Hygiene and Public Health is the contractor.

The other organization sponsoring research is the Power Lines Project of the New York Department of Health. Its work is being conducted at the Cancer Registry at Seattle and at the University of Colorado. The Seattle project, focusing on adults with leukemia, will investigate whether EMF exposure within their homes is greater than exposure of a control group. The Colorado study will try to determine if exposure to measured EMF within the homes of school-age children with cancer is greater than that experienced by a comparison group.

These research projects were undertaken to provide better information for questions raised in the wake of the 1979 Wertheimer-Leeper report, which alleged a cancer risk from EMF exposure. That study, conducted in the Denver area, reported an increase in childhood cancer among children living near what investigators refer to as "high current configurations." Other investigators, who had a similar study design in Rhode Island, were unable to confirm this finding.

Investigators in this country and abroad have conducted other studies on adults possibly exposed to EMF in the workplace. The occupations included electricians, welders, linemen, and power station operators. The diseases included leukemia, brain tumors, and other cancers. The diversity of findings is perplexing and deserves further research. One factor complicating the interpretation of studies is the lack of exposure information both within the allegedly exposed groups and in the general population. EPRI is attempting to remedy this by funding work to design instruments that can collect exposure data and to develop a methodology that provides estimates of annual exposures to designated groups.

Leonard Sagan, EA&E senior scientific adviser, commented, "We are not saying there is no relationship between EMF and cancer. We don't know whether these prior studies demonstrate a connection or whether these are pure chance relationships. The evidence of causation so far is not persuasive, but it's our responsibility to understand better whether there is a relation between electric fields and health effects." Sagan added that there is neither theory nor a body of animal data that would support a cancer-promoting effect of EMF. "As a matter of environmental health, the effects on humans exposed to EMF deserve EPRI attention, and projects are under way to provide better answers. In the meantime, most knowledgeable observers have concluded there is not sufficient evidence to justify any mitigating or remedial steps," he said. ■

CALENDAR

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

MARCH

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

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

APRIL

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

10–11
Marketing Perspective on Demand-Side Management
Scottsdale, Arizona
Contact: Ahmad Faruqui (415) 855-2630

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

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

23–24
Symposium: Cogeneration
San Diego, California
Contact: David Hu (415) 855-2420

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

MAY

1–2
Seminar: Investigation and Correction of Boiler Tube Failure
Charlotte, North Carolina
Contact: Barry Dooley (415) 855-2458

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

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

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

14–15
Seminar: Investigation and Correction of Boiler Tube Failure
San Antonio, Texas
Contact: Barry Dooley (415) 855-2458

14–16
Annual Review of Demand and Conservation Program
Tampa, Florida
Contact: Joseph Wharton (415) 855-2924

JUNE

10–12
Symposium: Fossil Plant Cycle Water Chemistry
Atlanta, Georgia
Contact: Roland Coit (415) 855-2220 or Barry Dooley (415) 855-2458

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

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

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

CATALYTIC COMBUSTION FOR STATIONARY GAS TURBINES

Controlling emissions of nitrogen oxides (NO_x) is a major concern of the electric utility industry in the United States. Many electric utilities that operate stationary gas turbines are using water or steam injection to meet current NO_x emission standards. However, because of the increase in heat rate associated with water injection and the anticipation of even stricter emission control requirements, there is a continuing interest in dry low-NO_x technologies. For several years EPRI has sponsored R&D to apply the emission advantages of catalytic oxidation to practical combustion systems for utility gas turbines. In addition, efforts by individual utilities, EPA, DOE, and the major turbine manufacturers have addressed such systems. This report reviews a recent EPRI test program and outlines the technical problems to be solved before catalytic combustion systems can become commercially available.

The rate of NO_x formation during combustion is strongly dependent on temperature conditions. The catalytic combustion concept has the potential to achieve ultralow NO_x emissions because catalytic reactors promote stable combustion of very lean fuel-air mixtures with flame temperatures of less than 3000°F (1650°C). Such low flame temperatures are below the threshold for NO_x formation. However, the limited temperature range in which current catalytic reactors can operate efficiently poses a difficult problem in applying the concept to practical combustion systems.

In an earlier EPRI-sponsored research effort (RP1657-1), Westinghouse Electric Corp. designed a catalytic combustor for stationary gas turbine application that employs a conventional primary burner upstream of a catalytic reactor element. As designed, the system consists of a primary fuel nozzle, the upstream burner, six secondary fuel nozzles, a secondary fuel preparation zone with contoured walls, a 16-in-diam (40.6-cm) catalytic element, and a transition duct leading to the turbine. The design also features air flow control by means of programmable compressor inlet guide vanes. Figure 1 shows an early test version of the combustor.

The upstream burner has two functions. During startup and part-load operation, the burner acts as a pilot to support combustion at turbine inlet temperatures too low to be sustained by catalytic reaction. At turbine inlet temperatures greater than 1700°F (930°C), fuel to the upstream burner is reduced and the burner acts as a preburner to heat compressor discharge air from 700°F (370°C) to the temperature required for catalytic reaction. The required catalyst inlet temperature ranges from approximately 800°F (430°C) for distillate fuel oils to approximately 1000°F (540°C) for natural gas.

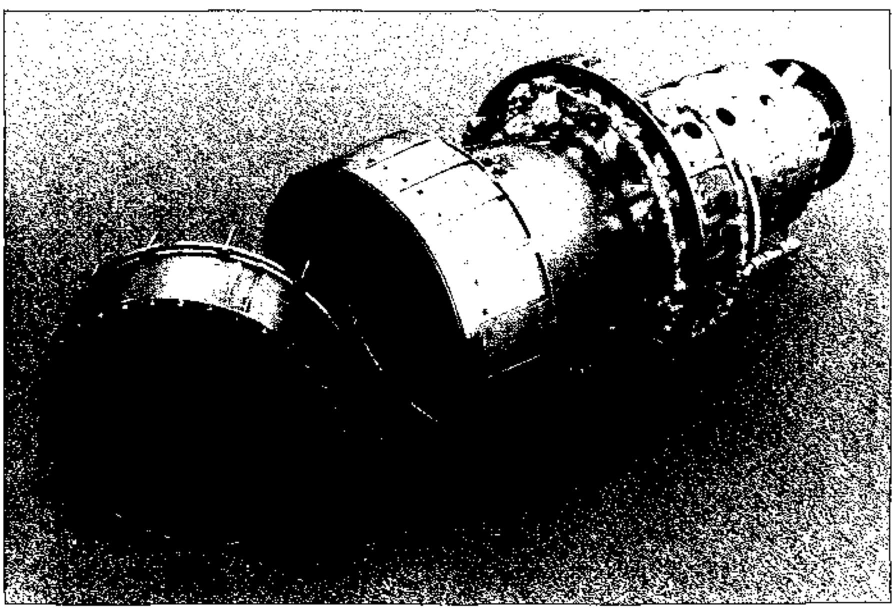


Figure 1 Low-NO_x catalytic combustor developed for stationary gas turbines. This preliminary test configuration differs slightly from the conceptual design in that its catalytic reactor element (left) is smaller in diameter (14 in; 35.6 cm) and it has eight secondary fuel nozzles (midway along combustor). Not shown is a fuel nozzle that fits onto the upstream end of the combustor to act as a pilot/preburner.

To maintain a constant load on the generator during the transition from pilot to preburner operation, air flow modulation is needed; this is accomplished by manipulation of the engine's compressor inlet guide vanes.

Under RP1657-3 Westinghouse recently conducted laboratory testing on an oil-fired, full-scale catalytic combustor to evaluate this design. The purpose of the tests was to obtain initial experimental data on the principal component technologies needed to apply catalytic combustion to oil-fired utility gas turbines. Three critical components were investigated: the pilot/preburner, the secondary fuel injection system, and the control system for transferring from the pilot to the catalytic operating mode. The principal means of evaluating the catalytic combustor's performance was by observing exit temperature patterns.

Test apparatus

The analysis and design work under RP1657-1 provided a recommended catalytic combustor configuration. The actual combustor used in the RP1657-3 test program was based on the same principle of operation and differed only in the size of the catalytic reactor element. In this operating approach a conventional primary nozzle and an electric ignitor provide a small conventional flame for starting the engine and bringing it up to approximately midload. At this point the primary fuel is reduced and the secondary nozzles are fueled. They spray in from the sides of the combustor about midway along its length. The secondary fuel is not intended to burn until it reaches the catalytic element, although it should mix with hot air and carbon monoxide from the primary zone and partly vaporize. In the catalytic element the secondary fuel is reacted at a lean overall fuel-air ratio (approximately 0.02). At such a ratio the desired turbine inlet temperature is reached without the formation of NO_x.

During the testing small changes in combustor configuration were made, which involved hole and cooling slot sizes and the arrangement for redistributing combustion and cooling air in the preburner. Six secondary fuel injection nozzles were used in each test configuration, and they were turned 30° downstream from the radial direction. Six axial swirlers were incorporated around each secondary nozzle to improve the mixing of secondary fuel with air upstream of the catalyst.

The 14-in-diam (35.6-cm) catalytic element was supplied by Engelhard Corp. Westinghouse designed and fabricated the Hastelloy-X cylindrical retaining ring, and Engelhard installed the catalytic element. The substrate was NGK-X, a magnesium-aluminum titanate material.

Test results

Analyses of the results from the RP1657-3 tests focused on previously identified problems involving (1) fuel-air mixture patterns and (2) fuel flows in the transition from primary to secondary operation. The instrumented combustor configurations were tested in four operating modes: primary fuel only, secondary fuel only (catalytic mode), combined primary and secondary, and fuel transfer. The secondary-fuel-only mode would not occur in an actual engine because the preburner is designed to provide temperature conditioning at all times for catalytic combustion within the element. This mode of testing is useful, however, to determine the performance of the secondary fuel–air preparation zone without interaction with the primary combustion zone.

Figure 2 shows a typical catalyst exit temperature pattern produced by the secondary fuel injection system used in these tests. The temperature distribution, when interpreted in terms of fuel-air ratio, shows the nonuniform nature of the fuel-air distribution. The variations in the fuel-air ratio over the catalyst inlet observed during the tests are considered unsatisfactory because they limited the ability to operate at high combustor load without exceeding the catalyst substrate material temperature limit of 2600°F (1430°C).

Fuel transfer mode testing was undertaken for the first time in this phase of the R&D program. Transfer from pilot operation (primary fuel only) to catalytic combustor operation (primary fuel and secondary fuel) must occur when the combustion turbine is carrying 55% of the rated load. Such transfers were performed under preprogrammed microprocessor control. Selected results from a typical fuel transfer are shown in Figure 3. As indicated by the fuel flows, the transfer was a functional success. It could not be counted completely successful, however, because of apparent autoignition, as indicated by the excursion of the catalyst approach temperature 27 seconds into the transfer operation.

Test data on several measured parameters, including fuel flows, wall temperatures, and combustor inlet conditions, were examined to try to determine the reason for this approach temperature excursion, but they indicated nothing unusual. It was concluded that the

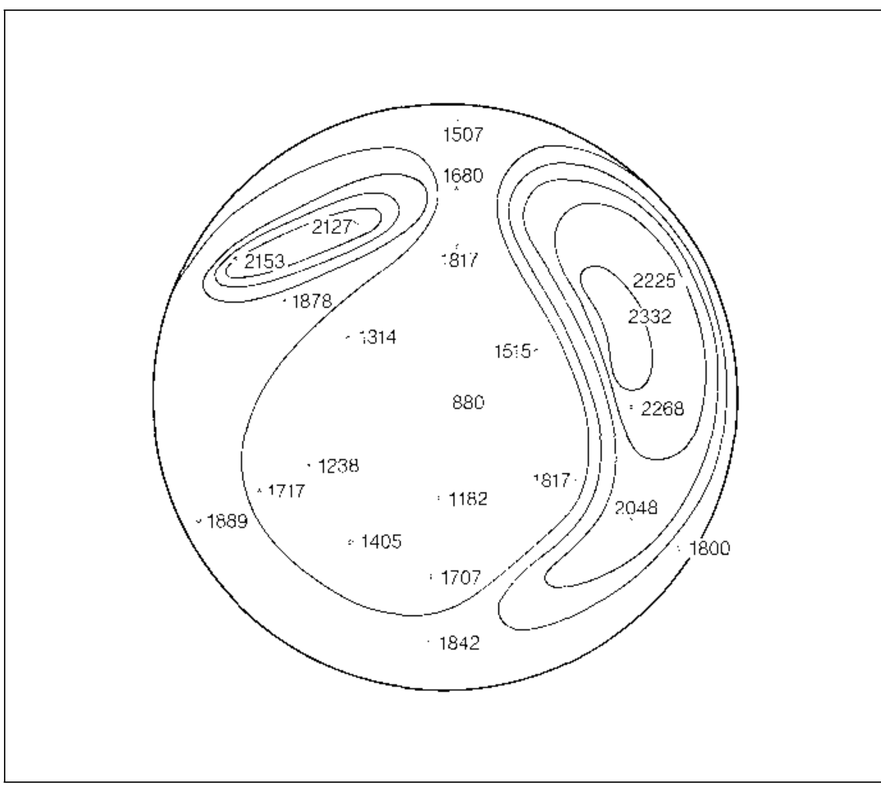
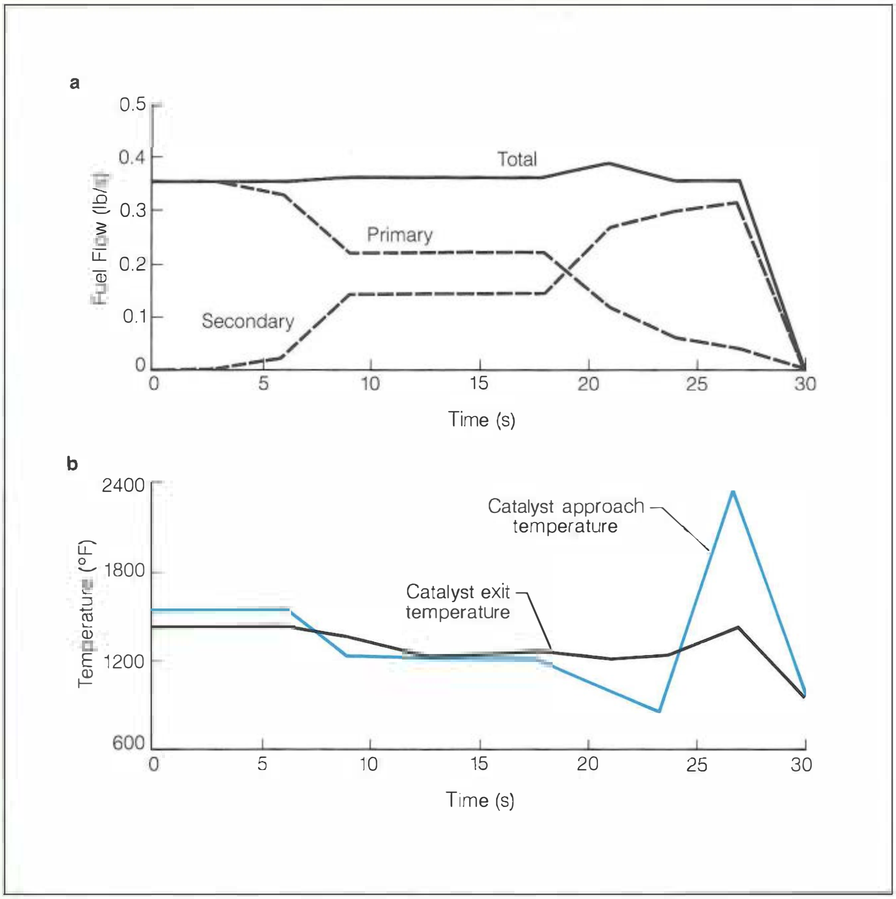


Figure 2 Temperature pattern (°F) at the catalyst outlet during a typical test of the catalytic combustor in the secondary-fuel-only mode. For this run the combustor inlet temperature was 813°F (434°C) and the nominal fuel-air ratio was 0.016. The unevenness of the temperature distribution indicates poor mixing of secondary fuel and air.

Figure 3 Combustor fuel flows (**a**) and catalyst approach and exit temperatures (**b**) during a test transfer from pilot operation (primary fuel only) to catalytic operation (primary and secondary fuel). The fuel transfer was accomplished as planned, with the total flow holding nearly constant. A sudden rise in the catalyst approach temperature, however, triggered fuel cutoff after 27 seconds. Researchers later surmised that swirlers around the secondary fuel nozzles had created conditions conducive to autoignition.



cause of the apparent autoignition during the fuel transfer was the use of air swirlers around each secondary fuel nozzle. The swirl number for these swirlers was calculated to be 1.2, which indicates a strong swirl. In addition to spreading a jet, which was the desired effect, strong swirl sets up a recirculation zone around each nozzle. It is surmised that as a result of these recirculation zones, chemically active species might have remained in the vicinity of the secondary nozzles long enough for autoignition to occur.

Future research objectives

Conclusions drawn from the full-scale tests conducted to date indicate that future development work should place a high priority on the mixing of secondary fuel and air. Poor mixing results in low efficiency, high emissions of unburned hydrocarbons and carbon monoxide, and the inability to operate at desired conditions. Despite the difficulty of operating with what turned out to be an extremely uneven mixture entering the catalytic element, the RP1657-3 tests were able to demonstrate a microprocessor control technique for transfer from the pilot to the catalytic mode.

In these tests an upstream piloting/preheating system was used to satisfy catalyst ignition constraints and engine turndown requirements. However, such upstream systems pose an inherent risk to catalyst survivability and durability. Hence basic design data for alternative approaches using downstream piloting systems are needed.

The results of the RP1657-1 design study clearly indicated that catalytic reactor temperature limitations significantly complicate the application of catalytic combustion technology to practical gas turbine operating systems. Considerable complexity is entailed by the need for variable air staging to meet catalyst midload efficiency requirements, pilot burner operation to enhance turndown, preburner operation to achieve catalytic ignition, and multiple-point fuel injection to obtain low NO_x emissions during baseload operation. The development of catalyst systems with lower temperature ignition requirements, enhanced sintering resistance, and higher operating temperature limits would clearly reduce such complexities. A great deal of basic design data in this area is needed.

One area not addressed in this program is the long-time durability of the catalyst and the catalytic reactor substrate. The development of practical catalytic combustion systems will require work to evaluate the effects of thermal transients on catalytic reactor life. In a related effort (RP1657-2), EPRI is sponsoring an evaluation of the thermomechanical behavior of two candidate ceramic substrate materials under thermal cycling conditions simulating utility gas turbine operation. The results of this project will be presented in a future status report. *Project Manager: Leonard C. Angello*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

ESP PULSE ENERGIZATION

Electrostatic precipitators (ESPs) are capable of removing more than 99% of the fly ash produced by utility coal-fired boilers and have been used for this purpose for more than 50 years. However, for a given ESP size, collection efficiency is reduced when ESPs are used to collect the high-resistivity fly ash generated by combustion of low-sulfur western coals. ESPs can be designed to accomplish 99+% collection efficiency with low-sulfur coals in one of three ways: by increasing ESP size, by flue gas conditioning, or by pulse energization (pulsing). In many cases, pulsing is more economical than the other alternatives. Current research has developed guidelines to help predict the level of performance that can be expected when pulse energization is added at a specific ESP installation.

Pulse energization occurs when a high-frequency, high-voltage pulse is superimposed on the base voltage of an ESP. This pulse generates an intense, diffuse, and uniformly distributed corona on the discharge electrode and a more uniform deposition of ionic charge on the surface of the collected ash layer, thus reducing the effect of high resistivity. Commercially available pulsers produce two types of pulse waveforms: a short pulse with a fast rise time of 1.5 μs, and a long, slow sinusoidal pulse with a rise time of 140 μs.

EPRI and the Environmental Protection Agency cosponsored a study in 1982–1983 to explore the potential of pulse energization for improving the collection efficiency of utility ESPs. Southern Research Institute conducted this research at EPRI's Arapahoe Test Facility, located at the Public Service Co. of Colorado's Arapahoe generating station (RP1868-1). The study was designed to provide information on pulsers that would allow utilities to predict, with some certainty, how pulsing would improve ESP performance.

Additional study objectives included providing guidelines for retrofit applications of pulsers on existing utility precipitators, measuring variations in precipitator performance with changes in the electrical parameters of pulse energization, and determining the dominant physical effects of pulse energization on the process of electrostatic precipitation. Study tasks included performance tests of a pilot-scale fly ash precipitator, laboratory studies of aerosol particle charging, and a survey and analysis of published data on full-scale precipitators.

Pilot-scale tests

The pilot-scale precipitator used in this study was installed on a side stream of the 110-MW Araphoe Unit 4 and received about 3500 actual ft^3/min (1.65 m^3/s) of flue gas at approximately 300°F (149°C). The precipitator power supply is capable of superimposing long or slow pulses of maximum -25 kV on a baseline voltage of -50 kV, at pulse repetition rates up to 200 Hz. The discharge electrodes on the precipitator are 0.115-in-diam (2.9-mm) wires on a harp frame. The wires were not rapped during testing. The collecting plate spacing can be set at 9 in (23 cm) with four parallel gas passages and a nominal specific collecting area (SCA) of 400 ft^2 per 1000 actual ft^3/min (37 m^2/[0.47 m^3/s]), or at 12-in (30-cm) spacing with three parallel gas passages and an SCA of 300 ft^2 per 1000 actual ft^3/min (28 m^2/[0.47 m^3/s]). Both spacing configurations were tested under conventional operating conditions and with pulsed energization. An SO_3 injection system was installed upstream of the ESP to vary fly ash resistivity between 1×10^{10} and 5×10^{12} ohm-cm.

Southern Research Institute continuously monitored outlet flue gas opacity and overall collection efficiency during the test period and also obtained particle size fractional collection efficiency data. During preliminary tests, maximum collection efficiency was experimentally derived by adjusting the baseline dc voltage of the precipitator to its spark limit and adjusting the pulse repetition rate for minimum outlet flue gas opacity. As the pulse repetition rate was increased, the dc voltage had to be decreased to prevent sparking. Precipitator performance improved rapidly and dramatically until the average electric power into the ESP became too low and performance began to deteriorate. Figure 1 shows this effect. These tests were performed with both long- and short-pulse waveforms, and negligible differences between the two were observed.

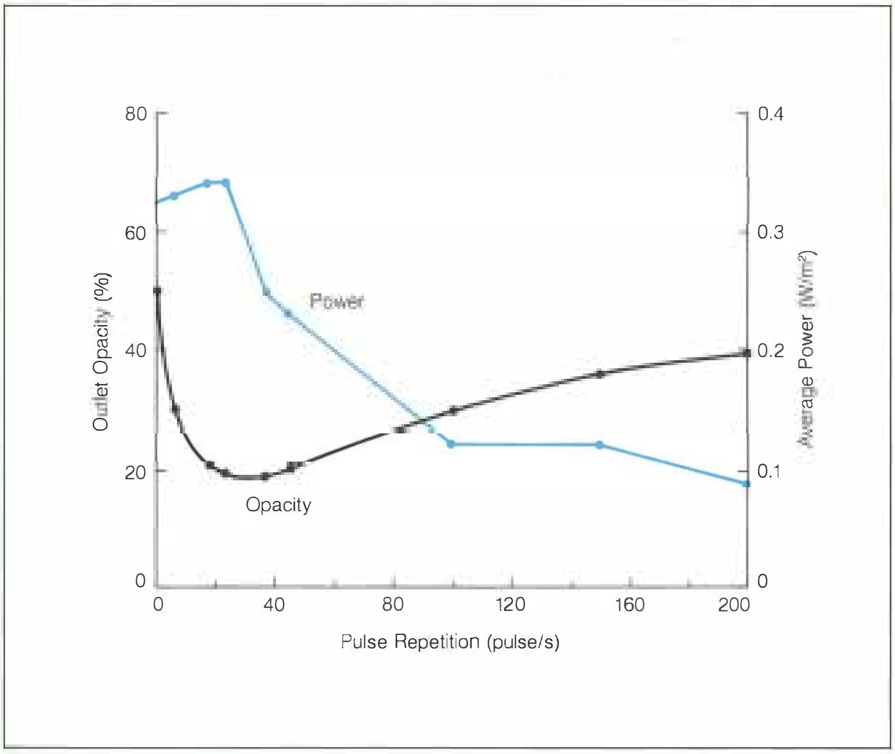
Curves of the type in Figure 1 will vary with both the fly ash resistivity and the precipitator sparking characteristics. Therefore, the optimal pulse repetition rate measured during these tests (25–50 Hz) cannot be arbitrarily assumed for any full-scale precipitator. However, these data do indicate that the dc voltage and pulse repetition rate in different electrical fields should be varied to find the optimal operating point for a pulse-energized precipitator.

Pulsing effects

Pulsed energization improves precipitator performance by creating a more uniform corona discharge. During each high-voltage pulse, the density of emitting points along each precipitator discharge electrode is greatly increased. Pulse repetition rates above ~25 Hz (regardless of whether collecting plates are clean or dirty) create a uniform corona glow along the discharge electrode. This corona leads to a more uniform distribution of ionic charge in the interelectrode space and to a more uniform deposition of ionic charge on the surface of the collected dust layer.

The electrical migration velocity of charged dust particles is the fundamental parameter of electrostatic precipitation that can be affected by pulse energization. Migration velocity can be increased by greater values of electric charge on individual dust particles and/or by greater values of electric field in the interelectrode space. Data show that pulsing does not significantly increase the charge on individual fine-dust particles. Accordingly, the im-

Figure 1 Outlet opacity (black) and average ESP secondary power density (color) in the pilot-scale precipitator compared with pulse repetition rate, with dc voltage at spark limit.



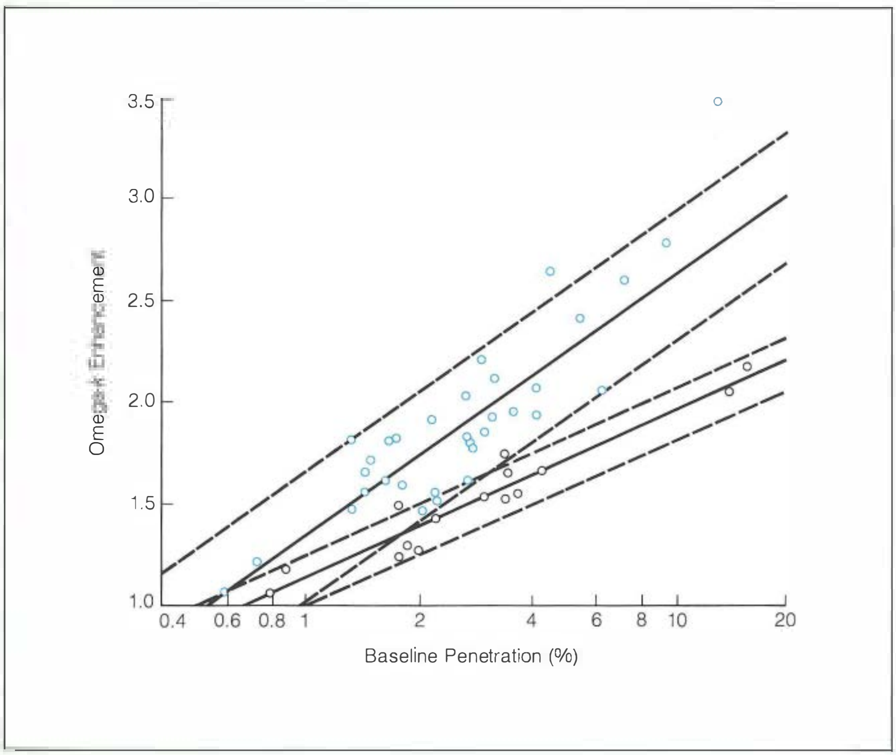


Figure 2 Omega-*k* enhancement factors compared with baseline penetration of the pilot-scale precipitator (color) and six full-scale fly ash precipitators (black). The dashed curves represent 90% confidence intervals; the solid curves, least-squares-fitted mean.

provement in ESP performance with pulsing is believed to result from a significant increase in the plate-area-average value of collecting electric field. The more-uniform corona discharge also acts to suppress some nonideal precipitator operating conditions: the reentrainment of collected dust, and the sparking and back corona that result from electrical breakdown in the collected dust layer.

Characterizing ESP performance

Collection efficiency is defined as the mass of particulate matter removed from the flue gas stream divided by the mass of such material entering the collecting device over a period of time. Penetration, on the other hand, is the mass of particulate matter escaping uncollected from the ESP divided by the total mass of particulate entering the device.

ESP inlet and outlet mass measurements to determine overall penetration were made during pilot-scale tests and analyzed in terms of the Matts-Öhnfeldt equation (P = penetration; E = efficiency):

$$P = 100 - E = 100 \exp^{-(\omega_k \ \mathrm{SCA})^{0.5}}$$

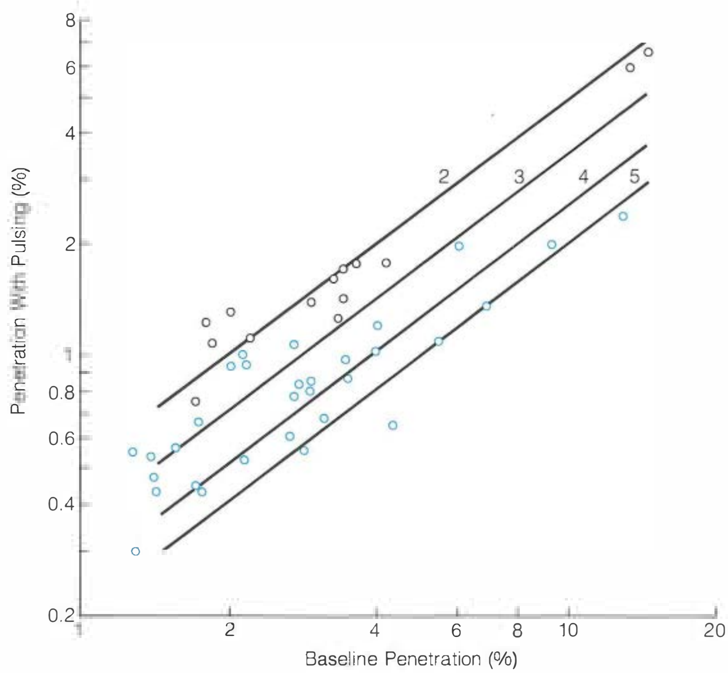
where SCA is the specific collecting area (ft²/[1000 actual ft³/min]) and ω_k (the omega-*k* parameter) is the average migration velocity of particles toward the collection plate. Improvement of precipitator performance with pulsing is conventionally measured as an increase in the omega-*k* parameter, most practically expressed as the ratio $\omega_k/\omega_{k\ \mathrm{dc}}$, where dc signifies baseline precipitator performance (i.e., without pulsing). This ratio is described as the omega-*k* enhancement factor: an expression of the average migration velocity with pulsing divided by that of the nonpulsed condition. Improvement in precipitator performance with pulsing, expressed in terms of the omega-*k* enhancement factor, correlates more closely with ESP baseline collection efficiency/penetration than with fly ash resistivity.

Results show that there are no systematic differences between omega-*k* enhancement factor data obtained with 9-in (23-cm) and 12-in (30-cm) plate spacing. Also, no significant performance improvement with pulsing can be expected for precipitators with baseline penetration below ~0.5% (collection efficiency greater than ~99.5%).

Predicting ESP performance

Performance data from the pilot-scale precipitator and from six full-scale precipitators described in the literature show no systematic difference in the beneficial effects of pulsing with the short, fast or long, slow waveforms. In Figure 2 the pilot-scale precipitator data are compared with 17 data points from the six full-scale units, which were fitted with pulse power

Figure 3 Baseline penetration and penetration with pulsing of the pilot-scale precipitator (color) and six full-scale fly ash precipitators (black), with penetration reduction factors.



supplies having widely different pulse waveforms and electrical operating parameters. Values of omega-*k* enhancement for the full-scale precipitators follow the same type of trend as the values for the pilot-scale precipitator, although the absolute improvement levels are less for the full-scale units.

Correlations of these pilot- and full-scale performance data can be used to estimate the performance improvement that can be expected by pulsing any given ESP. Comparing measurements of baseline penetration from any ESP with the omega-*k* enhancement data in Figure 2 allows the calculation of the anticipated effectiveness of pulsing. The lower omega-*k* enhancement data shown for the full-scale precipitators probably result from rapping reentrainment and a variety of electrical and mechanical defects that are likely to exist in the field, defects that pulsing cannot correct. By comparison, the pilot-scale precipitator was in good operating condition for this project and the electrodes were not rapped during tests.

In addition to using the ω_k enhancement to correlate precipitator performance data, ESP penetration with pulsing can be plotted directly against baseline penetration, as illustrated in Figure 3. The straight lines superimposed on the figure show penetration reduction factors of 2, 3, 4, and 5. The full-scale precipitator data lie mostly between reduction factors of less than 2 and 3. Solely on the basis of theory, an enhancement factor of 2 means that an ESP equipped with pulsing would be half the size of one without it. In practice, the ESP size reduction would not likely be as significant. The penetration reductions shown in Figure 3 are based on data for precipitators with the following characteristics: operating difficulties resulting from electrical problems that are specifically caused by high-resistivity fly ash; measured baseline collection efficiency no higher than 99% (i.e., baseline penetration of 1% or more); SCA in the range of 150–350 ft^2 per 1000 actual ft^3/min (14–33 $m^2/[0.47\ m^3/s]$); straight-wire discharge electrodes; and at least half of the SCA in the direction of gas flow pulse energized. *Project Manager: Walter Piulle*

FOSSIL FUEL PLANT CYCLING

Historically, utilities have been primarily concerned with meeting peak demand. The industry view was that if the peak demand could be met, the low off-peak demand should not pose major concerns. However, the addition of nuclear power plants for baseload generation and the lower-than-expected load growth in recent years resulted in excess capacity at off-peak periods. To optimize system generating costs, utilities use nuclear plants (which have relatively low operating fuel costs) for baseload and fossil fuel units to accommodate daily load swings and meet peak demand. Cycling of units originally designed for baseload operation creates equipment availability concerns in the entire power plant. EPRI is devoting significant resources to address the technical and economic limitations of fossil fuel plant cycling. This report summarizes several completed projects and discusses the status of others in progress.

Boiler considerations

The utility industry has identified key problems that result from cycling operation (Table 1). Thick-walled steam generator components (such as steam drums, superheater headers) have been watched closely for possible failure from excessive thermal stress. Boiler startups have generally been limited by simple but effective rules governing the rate of temperature change in key areas. In the past these limits did not greatly restrict unit availability because fossil fuel units were operated in a baseload mode. But when baseload units are converted to cycling duty, the startup limit may no longer be adequate to protect against excessive stress and loss of life.

Therefore, utilities must consider cyclic stresses caused by more-rapid temperature changes in the boiler. These temperature differences may occur through the thickness of a containment or between contiguous components. The steam drum and superheater outlet headers, for example, are among the thickest components in the boiler and can be affected by thermally cycling the boiler. One EPRI study of a cycling once-through boiler found that on/off daily cycling requires design changes before the boiler can be cycled on a regular basis (CS-2340). However, even design changes may not prevent thermal shock in a once-through boiler when cold water enters the hot boiler, so new operational procedures may be appropriate.

EPRI is developing a boiler thermal stress and condition analyzer that can evaluate boiler

Table 1
CYCLING OPERATION PROBLEMS

Boiler	Turbine	Balance-of-Plant Components
Cyclic stress; loss of life	Cyclic rotor stress; loss of life	Back end equipment turndown
Furnace implosion/ explosion	Thermal stress	Acid dew point condensation at back end
Flame scanning/ monitoring	Solid-particle erosion	Water chemistry monitoring; chemical cleaning
Burner and pulverizer turndown	Vibration during startup/shutdown	Distortion/internal rubbing of boiler feed pump
Mill fire/explosion	Turbine seals	Cooling-tower freezing

component conditions at high temperatures and pressures or high thermal stresses (RP1893). The analyzer monitors critical boiler components, evaluates cumulative creep/fatigue damage, and calculates life expenditure. Utilities can use it as a guide to maximize boiler life. Combustion Engineering, Inc., is developing this device for EPRI and is demonstrating a prototype at the Ravenswood plant of Consolidated Edison Co. of New York. Figure 4 illustrates the monitoring points.

In another project, Westinghouse Electric Corp. set up a data acquisition system at Commonwealth Edison's Collins Unit 5 for the analysis of metal temperatures in cycling turbines and boilers (CS-3800). Researchers monitored a total of 249 variables continuously for 15 months. Using the collected data, project personnel ran an extensive boiler model to study transients in cycling operation.

Turbine considerations

Apart from differential expansion and rotor vibration, transient thermal stresses in the large high-temperature components (particularly the turbine rotor) is recognized as the most critical limitation. Turbine thermal stresses result, in part, from different rates of temperature change between the boiler and the turbine over time. For example, after shutdown the boiler cools at a faster rate than the turbine. When the unit is restarted, the initial steam temperature is lower than the turbine metal temperature. Later in the startup sequence, the steam temperature may become excessively high in comparison with the turbine metal temperature. These temperature differences produce thermal stresses in the turbine. On-line turbine thermal stress analyzers (similar in concept to the EPRI boiler stress analyzer) are now commercially available.

Allowing steam to bypass the turbine during startup may be an effective measure against undue thermal stresses in cyclic turbines. Turbine bypass systems improve operation in the following ways.

- Steam flow is established in the reheater early in the startup; control of the firing rate is thus limited by the allowable rate of drum heating rather than concern for reheater protection. This procedure reduces overall startup time.

- Steam from the boiler is not admitted into the turbine during startup while the steam temperature is much lower than the turbine metal temperature. This procedure minimizes the temperature difference that can reduce turbine component life.

- Corrosive agents produced in the superheater and reheater tubes exfoliate during startup. Carried by the steam to the turbine, these agents can cause erosion of turbine nozzles and blades. Bypassing the turbine during startup may reduce such solid-particle erosion.

- The high-pressure turbine bypass valve can control the rate of pressure rise and hence the rate of temperature rise in the boiler drum. This control is crucial in reducing thermal stresses in the drum.

- The boiler can continue to operate during a turbine trip that results, for example, from loss of electrical load. In a conventional arrangement, a turbine trip would also lead to a boiler trip because the boiler would continue to produce steam and the boiler pressure would become excessively high. Therefore, the bypass system, which allows continued boiler operation, provides for faster unit startup after a turbine trip.

An earlier project compared costs and cycling performance of generating units with and without bypass systems (RP1879-1). An important finding was that design features and operating practices greatly influence bypass system effectiveness in reducing startup times and costs. The follow-on effort to that study assesses the quantitative benefits of bypass systems (RP1184-3). This project explores the causes of high startup costs by combining field measurements on units with and without bypasses with dynamic computer analyses of plant transients. The project will identify corrections to operating practices and equipment limitations that could save significant startup costs and minimize component life expenditure.

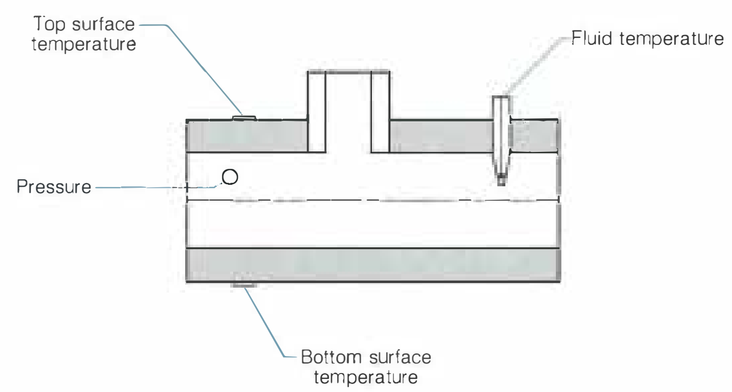


Figure 4 The boiler stress analyzer monitors critical boiler components, evaluates cumulative creep/fatigue damage, and provides operation limits to avoid excessive stresses. This is an example of the monitoring points for a typical header cross section, such as the headers for the horizontal superheater outlet, the superheater pendant outlet, and the reheater pendant outlet.

Balance-of-plant considerations

Waterside corrosion, exacerbated by deteriorating water quality, is another major problem that results from cycling operation. Oxygen infiltration and deposition of silica, copper, and iron cause corrosion, and this is particularly evident at low loads. Areas in the water-steam cycles that require review are the feedwater, boiler water, steam, condensate, and makeup water. One ongoing project that evaluates the effects of cycling operation on corrosion product transport to the water-steam cycle is RP1184-9. NWT Corp. is tracking the transport of corrosion products through the water-steam cycle at Florida Power & Light Co.'s Port Everglades station (a cycling plant) by taking extensive samples for water chemistry analysis at selected locations. Recommendations will be developed for curtailing the transport of corrosion products during cycling operation to reduce boiler and turbine corrosion-related failures.

A planning study on the integration of environmental controls in cycling fossil fuel plants has just been completed (RP1184-6). This study analyzes all the critical issues resulting from the cyclic and turndown operations of plant emission control equipment. Optimal operation of electrostatic precipitators and SO_2 scrubbers, fly ash handling equipment, and control of reagent feed in wet scrubbers are among some of the key concerns. The study outlines R&D for each critical issue and a technical plan for follow-on work.

The development of the modular modeling system (MMS) has resulted in a computer code that can model thermodynamic and control processes for dynamic analysis of plant performance under cycling conditions (RP1184-2). The current MMS library has more than 60 modules representing different fossil fuel and nuclear plant components. All modules are self-contained and can be interconnected to represent any specific plant configuration. Actual utility applications of MMS range from steam attemperation control to the modeling of an entire coal-fired unit.

Further R&D with MMS includes simulation of low-load operation in a fossil fuel plant (RP1184-11), an interactive and color graphic plant analyzer (RP1184-12), and air/gas dynamics (RP1184-15). The analyzer, which continuously displays all key variables on a CRT, allows plant operators to observe and better understand plant processes (*EPRI Journal*, December 1984).

Strategies and guidelines

Analytic tools, such as the MMS, are useful in evaluating different startup strategies for cycling operations. They can assess relative plant performance, as well as the economic advantages and technical limitations of the strategies. Under EPRI contract, Babcock & Wilcox Co. is now developing such a tool (RP1184-4). A plant model constructed by MMS simulates the effect of different operating strategies, which can be compared by using a cost function representing both short- and long-term cost penalties. EPRI has initiated a follow-on effort to develop an on-line startup adviser that can recommend startup procedures based on calculated conditions and estimated costs. The result will be a program compatible with personal computers. EPRI is soliciting interested utilities to host demonstrations of this on-line startup analyzer.

EPRI has recently launched a major program to complement all ongoing cycling-related projects. A team representing utilities, manufacturers, and architect-engineers will be selected to develop strategies and guidelines for converting a baseload fossil fuel unit to cycling duty. The project will be carried out in two phases. Phase 1, planning and development, will consist of several steps.

- Selection of unit and future cycling scenarios
- Identification of plant components affected by cycling
- Inspection of current conditions and field testing to determine cycling effects
- Determination of operating and maintenance strategies and equipment design changes necessary to mitigate cycling effects
- Evaluation and cost-benefit analysis of the changes
- Selection of the projects and implementation schedules for the unit
- Production of a generic set of guidelines for cycling conversions

In a later demonstration phase (phase 2), the host utility will implement the selected strategy, and EPRI will monitor and assess unit performance.

Forecasts indicate that the rate of load growth for the utility industry will remain low throughout the decade. Cycling operation of fossil-fuel-fired plants will therefore be essential for most utilities.

A workshop held in November 1983 in Chicago attracted more than 200 industry representatives. Participants identified major technical issues associated with cycling operation and provided input to EPRI R&D. Future work will emphasize such key areas as water chemistry, back end optimization, variable-pressure operation, boiler turndown, turbine and auxiliary equipment operation at low load, and heat rate improvement at low load. In particular, the conversion demonstration will bring together a well-balanced team from utilities, architect-engineers, and manufacturers for a thorough study of conversion of baseload units to cycling operations. EPRI's goal is to develop recommendations and guidelines for reliable and efficient operation of cycling fossil fuel plants. *Project Manager: Frank Wong*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Power plant electrical reference book

Useful results of EPRI projects, in the form of both hardware and software, are becoming available in an ever increasing stream. It should be of considerable value to the utilities to capture the essence of this work in a more concentrated manner for quick and easy reference by those who have to apply this information. This has been done in the overhead lines area through publication and periodic revision of the highly regarded set of EPRI transmission line reference books. In a similar manner, the *Power Plant Electrical Reference Book* is being developed to bring together the results of EPRI research in this area. In addition to a compilation of up-to-date technical information from many scattered sources, this reference will be of value to power plant personnel (RP2334).

In the past, several electrical equipment manufacturers published reference books that dealt with specific technical areas—for example, *Electrical Transmission and Distribution Reference Book*, published by Westinghouse Electric Corp., and *Industrial Power Systems Handbook*, published by General Electric Co. Many utilities state that reference books such as these have been very useful in making decisions on design, system planning, and preventive maintenance and in dealing with plant emergencies. Unfortunately, this practice by manufacturers to publish or update reference books in the electrical power apparatus field has essentially ceased, mainly for economic reasons.

A comprehensive and up-to-date reference book can save utilities time and money in many ways, such as the following.

- Prevention of forced outages through proper installation, application, and protection of station auxiliary equipment
- Recognition of potential problems and their prevention
- Suggestions for maintenance methods to ensure trouble-free equipment operation
- Reduction in equipment installation time and expense
- Proper specification of equipment being ordered
- Better coordination and integration of system components

The objective of the project is to develop a practical reference book that will be useful to power plant site and other utility personnel in dealing in a timely fashion with everyday problems associated with various electrical hardware (e.g., motors, generators) and various electrical phenomena (e.g., subsynchronous resonance, bus transfer, grounding). The book's 15 chapters will cover the following topics.

1. Electric generators
2. Power transformers
3. System planning
4. Electrical wire and cable
5. Grounding and lightning protection
6. Electric motors
7. Switchgear, unit substations, motor control centers, and generator circuit breakers
8. Station protection
9. Dc systems
10. Electrical control and instrumentation
11. Cathodic protection
12. Electric pipe heating
13. Communications
14. Electrical noise reduction
15. Plant improvement and modification

A utility survey determined the various topics to be included in the book. A literature survey of the detailed information has also been completed. At present, the writing of the various chapters is in progress. A utility review committee has been set up to monitor the project to ensure that the final product is in tune with the needs of utilities. *Project Manager: D. K. Sharma*

Improved motors for utility applications

The Industry Assessment Study conducted under phase 1 of this project was reported in the December 1982 issue of the *EPRI Journal*. (RP1763-1). The IAS reported failure data on 4797 power plant motors, and failures were categorized by motor components. Data analysis identified three broad areas for further research: motor data collection and operational improvements, motor technology, and motor application. Motor technology improvement efforts include work on bearings, stator windings, and squirrel cage rotor windings. Motor application improvement efforts include studies on bus transfer; conveyor, pulverizer, and fan drives; and the effect of harmonics on motors. Work in these research areas is being done by General Electric Co. (RP1763-2).

The data analysis does not cover all the motor data that were received. Data were also received on an additional 1515 motors, and an analysis has now been made of the entire data base, which includes 65 utilities, 168 generating units, and 6312 motors. This analysis will be published in early 1985.

Work continues in the area of motor technology and motor application improvements. The bus transfer studies are nearing completion, and a report is expected in early 1985. This effort includes high-speed and soft (in-phase) bus transfer studies, as well as the effect of adjustable speed drives.

To better determine insulation impulse voltage characteristics, short-time breakdown tests are being conducted on representative turn-to-turn and ground wall insulation, using direct voltage, 60-Hz alternating voltage, and impulse voltage. Formed coils will be fabricated, selectively subjected to voltage aging, and tested for dielectric strength when subjected to impulse voltage. A method of calculating voltage distribution in a stator winding exposed to impulse voltage has also been developed. Results of all this work will be published in early 1986.

The application of belt conveyor drives, coal pulverizer drives, and high-inertia fan drives requires careful motor-load coordination. Studies are being conducted to produce recommended practices, possible areas of increased efficiency from the refinement of specifications, design impact, and the application of new drive concepts. This work is expected to be completed by early 1986.

The impact of harmonics on motors is also being studied to provide data on the degree to which harmonics affect motor life and performance.

The IAS identified rotor problems as one of the causes of failure. To address this issue, work is under way to improve the state of the art in rotor thermal prediction techniques.

Forty-one percent of the motor failures analyzed in the IAS were bearing-related. Of the total number of bearing-related failures, nearly 40% were attributed to sleeve bearings and 20% to bearing seals and oil leakage. Because bearing-related failures were the largest single contributor to the motor failures reported, work is under way to study horizontal motor sleeve bearings and seals as a means of improving motor reliability. A review has been completed on the state-of-the-art in motor sleeve bearings and seals. Areas for improving bearing reliability have been identified, particularly in the lubrication systems of sleeve bearings. The entire work on sleeves and bearings will be reported to the utility industry in early 1986. *Project Manager: D. K. Sharma*

Generator standstill frequency response tests

Substantial benefits could accrue to a utility if it could safely reduce excessive stability margins by as little as 2%. These margins are determined after conducting transient stability analyses of the system. The accuracy of these stability studies is directly related to the quality of the transient models of the generators used in the analysis. To confirm the transient parameters for large synchronous generators, field tests must be conducted on the equipment. Until now field test procedures have not been endorsed by most utilities.

What is needed is a standard method to determine machine parameters directly from field tests. Hence, the objective of this project (RP2328) is to develop such response tests, starting with those developed under RP997; these tests will be coordinated with the verification testing of a representative sample of turbine generators.

Comprehensive field testing is being conducted at several utilities. Prior to unit startup after an outage, standstill frequency response tests are conducted on the generator. When the unit is up to synchronous speed, a number of stator decrement tests are performed. Both these sets of data are being evaluated to determine the limits of correlation between the two methods of field testing.

In addition to confirming field test methods, one of the utilities will be comparing the results of an earlier EPRI research project (RP1288) with the findings of RP2328. This will establish a correlation between field test results and calculated results, which were obtained from three-dimensional finite element analysis techniques using the detailed geometry of the generator. Preliminary results should be available during the latter part of 1985 so utilities can determine which of the various testing and analytic techniques is acceptable for their purposes. The project is scheduled for completion at the end of 1986. *Project Manager: James S. Edmonds*

DISTRIBUTION

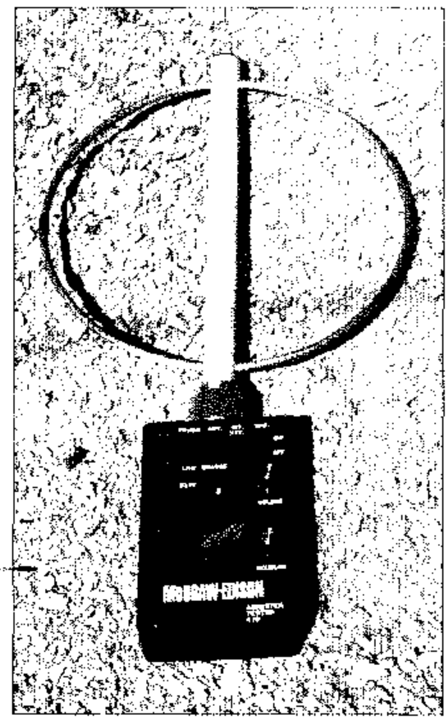
Surge arrester tester

Since our last status report (*EPRI Journal*, October 1983) on this project to develop an in-service surge arrester tester (RP2004), Wisconsin Electric Power Co. used a prototype tester to survey distribution lines, and the results were encouraging. During the course of the field trial, WEP identified two defective arresters and located a number of other abnormal conditions, such as cracked insulators and loose hardware.

Thus it appears that this device (Figure 1) has the capability to identify a broader range of abnormal conditions than our original objective included. Although radio interference (RI) detection instruments can detect items like cracked insulators and loose hardware if the radiated interference is great enough, our tester differs from such equipment in a number of significant ways. Great sensitivity and directivity are built into this convenient-to-use, hand-held instrument. It is based on a unique technology to convert the received electromagnetic radiation into easily interpreted audio and visual indications. The cost of the detector will be far less than that of conventional, vehicle-mounted RI detection equipment.

We are now producing prototypes for extended evaluation by eight utilities. We believe a six-month trial period should be long enough for bugs to appear and for the utilities to evaluate performance. Following this period, any needed or desirable modifications will be made, and the detector will be available—probably in the third quarter of 1985. *Project Manager: Herbert Songster*

Figure 1 Although the final production version will be slightly different, this illustrates the physical features of the tester. The directional antenna has a diameter of 12 in (305 mm). The battery can be recharged by using the cigarette lighter socket of a car or truck.



Advanced tree-trimming equipment

Electric utilities must trim trees to maintain proper line clearances, thereby preventing service interruptions. An estimated $500 million is spent every year on this activity. Because tree trimming is labor intensive, reducing labor could result in substantial cost savings to the utilities.

An earlier EPRI study determined that tree-trimming productivity could be improved by reducing the amount of time required to set up for a cut (RP1780-1). This current project is to develop advanced tree-trimming equipment that will speed setup time for a cut, which could improve productivity by 20% or more (RP2358). The devices being developed are a pantograph-supported telescopic pole saw for a mechanized tree-trimming crew, and engine-powered, climb-crew tools and a rope thrower for a climbing tree-trimming crew.

The pantograph-supported telescopic pole saw will be mounted on a bucket truck. The pantograph will support the weight of the boom holding the pole saw, allowing a person to handle a longer pole without having to support its weight. The pole's telescopic construction provides greater flexibility in making cuts both close to and a distance away from the bucket. Hence, productivity is increased by not having to reposition the bucket as often, as well as by the ability to make cuts from a position previously unreachable by the bucket.

The engine-powered climb-crew tool and rope thrower are intended to speed the activity of a tree-climbing crew. The rope thrower will reduce substantially the number of tries needed to place a safety line before the individual climbs the tree. In addition, the rope thrower should be able to place the line higher in the tree than a person could hope to throw the rope.

The engine-powered climb-crew tool comprises a small gasoline engine to power a lifting device that places the individual in the tree, a pruner, and a small chain saw. These power tools will lift and cut more quickly than crews performing the same functions manually, thus increasing climb-crew productivity. *Project Manager: Harry Ng*

Transient and midterm stability

Power systems have grown larger and interconnections between utilities have grown more complex in recent years. Therefore, the need has increased for power system planners and operators to analyze power system transients after the sudden loss of lines or generators. Experience indicates that the effects of such disturbances on large systems are widely felt for as long as several minutes. However, traditional analysis programs have been designed to be accurate for about 10 seconds or less.

The goal of this research project is to develop a program that would extend the period of analysis by adding models of equipment that come into play during disturbances up to 5 minutes long (RP1208). A second objective is to reduce the required computer time to acceptable levels (computer time of 1 hour per second of model time is not unusual). The new program is based on the transient/midterm program developed under RP745 and other work done in RP670 and RP763. New features include an improved, two-terminal dc transmission line model, as well as improved machine and auxiliary models. An enhanced output analysis package has also been developed. A new uniform frequency algorithm is expected to keep computer use times within acceptable limits.

Host utility testing began in December 1984 and will be completed by mid 1985. Six utilities are involved in the testing: Consumers Power Co., Ontario Hydro, Pacific Gas and Electric Co., Philadelphia Electric Co., Public Service Co. of Indiana, and Western Area Power Administration. Boeing Computer Services Co. and Ontario Hydro are providing support to the IBM and VAX versions of the program, respectively. After any necessary modifications, the program will be available for distribution through the Electric Power Software Center. *Project Manager: John Lamont*

Harmonic analysis software

Harmonics are voltages and currents at frequencies above 60 Hz (integral multiples) that cause distortion of the standard sine wave and do not decay over time. Harmonics are caused by nonlinear loads, such as rectifiers, variable-speed motor drives, saturated transformers, and HVDC terminals—types of devices existing today and becoming more prevalent.

Utilities are increasingly concerned that harmonic levels in transmission and distribution systems are becoming unacceptably large. Customer nuisance complaints, excessive use of capacitor bank fuses, and capacitor bank damage are often traced to harmonic sources that may be far away from the problem area. Quality-of-service questions are raised when large industrial customers replace old motors with harmonic-causing modern machinery.

Since early 1984 EPRI has been distributing a computer program, HARMFLO, that simulates the creation and propagation of harmonics in balanced three-phase systems (the January/February 1984 issue of the *EPRI Journal* discusses HARMFLO). In that time many utilities have successfully used HARMFLO for analysis of harmonics on their transmission or distribution systems.

After completion of the initial project (RP1764-7), EPRI initiated a follow-on project (RP2444-1) with Purdue University and Minnesota Power & Light Co. (MP&L) to remove several program restrictions and validate HARMFLO predictions against field test results. As a result, a new version (version 3.1) of the program will be available from the Electric Power Software Center in the first quarter of 1985. The new version differs from version 1.0 in its modeling capability (12-pulse converters, HVDC controls, and zero-sequence models were added), efficiency, and size (100-bus studies are now possible).

Field tests have been recorded on the MP&L system, where harmonics were injected into the power system by means of monopolar and filterless operation of an HVDC line. Preliminary agreement between HARMFLO results and field tests has been quite good (within 10%), especially considering the relative crudeness of the model used. In other tests sponsored by utilities, good correspondence with field tests was also achieved, but it was found that the load models used had a profound effect on the results. Documentation of field test comparisons is slated for publication in mid 1985. *Project Manager: James V. Mitsche*

TRANSMISSION SUBSTATIONS

Semiconductors for EHV switching stations

Because of the small, but still finite, resistance losses of all semiconductor devices while conducting, it is not considered economical to apply them in series with power lines in lieu of mechanical breakers. However, it is a distinct possibility that a parallel combination of a semiconductor switch and mechanical breaker might well combine the advantages of both and, at the same time, reduce the ruggedness required of either when used alone.

Two objectives were pursued by General Electric Co., the contractor in this investigation (RP1511-2) The first of these started with modeling to investigate some of the ways in which a surge device should differ from a normal device (and package). Development was then carried on to obtain the desired doping profiles specified by the modeling. This was followed by further process development to achieve defect-free devices of sufficient area (50-mm diam). In a second facet of the work, asymmetric and symmetric thyristor operations were modeled to determine the conditions suitable for application of each.

The necessary doping profiles for asymmetric thyristors were attained, but devices of sufficient area did not survive breakdown tests. Although gross crystal defects developed in the early runs were eliminated, residual defects (principally at the wafer edges) resulted in the large-area 5–6-kV devices having maximum breakdown voltages limited to 1000 V. Cutting the large wafers into 5-mm-square chips resulted in a significant number of small devices that achieved the theoretical maximum of 6.5 kV.

Design trade-offs of asymmetric and symmetric thyristors at operating voltages from 5 kV to 20 kV over a temperature range of -200 to 125°C were modeled in surge and steady-state operation. This showed that in applications where equal forward and reverse blocking capability is required, it is better to have two 5-kV symmetric thyristors than one 10-kV asymmetric thyristor in series with a 10-kV diode.

The work reported here has no immediate effect on utility operations. However, along with RP669-1 and -2 (EL-932, EL-1349, EL-3643), it represents continuing progress in modeling and fabrication of light-triggered thyristors with lower losses and concomitant lower operating costs. Overall, HVDC converters have benefited significantly over the years from earlier work. It is probable that continuing future benefits will become apparent for HVDC, breakers, and possibly VAR generators. Additional work is being carried out under RP2443. *Project Manager: Gilbert Addis*

OVERHEAD TRANSMISSION

Wood pole structure design

In terms of the number of structures, wood is by far the dominant material used for transmission and distribution structures in the United States. However, wood exhibits highly nonlinear material behavior, as well as wide variations in strength and stiffness characteristics, even within a given species.

The impact of this variability in the characteristics of wood on the design of wood transmission and distribution structures is substantial. The variation in characteristics is usually accounted for by the selection of conservative design loads, load factors, and average material properties on the basis of field experience. This field experience is embodied in the National Electrical Safety Code and individual utility loading agenda.

This approach to design has worked well in minimizing the number of failures in the field, but the apparent reliability has been at the expense of possible overdesign of the structures in the line. This deterministic approach does not permit an evaluation of the probability of line failure, of the actual strength of a line at any given point in the useful life of the line, or of the relative efficiency of one design over another. The development of reliability/probability–based design theory and associated methods in recent years promises to make it possible to quantify the reliability of a given line design or line component.

Over the past six years the task of the EPRI project on the probability-based design of transmission lines (RP1352) has been to convert the theoretical bases of probability design into a practical tool for transmission line design. A number of efforts have been ongoing.

- Definition of methods and concepts in a form usable by utility engineers
- Definition of loads and resistance data necessary to implement probabilistic methods
- Expansion of the transmission-size wood pole data base through full-scale pole testing
- Development of nondestructive evaluation techniques to determine material characteristics of wood poles

The *Guide for Reliability-Based Design (RBD) of Transmission Line Structures*, now in draft form, is comprehensive, including design methods, load-producing phenomena, material and structural resistance data, and analysis methods. The *Guide* will be a valuable document in industry efforts to incorporate probability/reliability methods into design codes. It also provides utility engineers with a single source on reliability design methods, which should lead to broader use of RBD within the industry.

As a part of RP1352, studies have been completed that address the definition of wind and ice-loading phenomena required by RBD methods. The results of these studies have been included in the sections on the influence of geographic and local topographic variation on wind speed, determination of wind speeds from annual extremes, available sources of wind data, development of a local wind-speed data base, and combined loading by wind and ice. A review process is now beginning, and the *Guide* will be published in mid 1985.

To implement the methodology in the *Guide*, data on loads and strengths are needed. For example, the available data on the strength of new and in-service wood poles were very limited at the beginning of the project. This led to the implementation of full-scale wood pole tests. With utility cooperation, a pilot test program was initiated to determine if the reduction in fiber stress with time in service could be quantified. Approximately 225 poles were tested to destruction in the Research Institute of Colorado's wood-testing laboratory. This full-scale testing greatly expanded the existing data base of strength characteristics of wood poles, but development of a nondestructive evaluation (NDE) method to determine wood pole strength and stiffness characteristics required additional correlation between characteristics determined through full-scale destruction testing of poles and parameters determined through nondestructive procedures.

Through the support of the Southern Pressure Treaters Association, the Western Wood Preservers Institute, and the Western Red Cedar Association, a total of 390 new southern pine, Douglas fir, and western red cedar poles, plus transportation, were donated to the project by pole suppliers. These poles were subjected to extensive NDE testing and then tested to destruction. This testing is complete, and the data will soon be formally available.

Extensive evaluation of these test data led to the development of two NDE procedures. The first NDE method is based on measurements of the time of travel of sound through a wood pole. The hardware and technical support necessary to use this method are commercially available to utilities today. This NDE procedure accurately predicts the frequency distribution of material strength for poles in a group of poles or in an entire line; however, the strength of individual poles cannot be determined by this method.

TechWare of Fort Collins, Colorado, has developed a state-of-the-art device called a sonic wave processor to accurately measure the time of travel of an induced sound wave through a wood pole or wood member (Figure 2).

The sonic wave processor is a user-friendly device, programmed to display a step-by-step sonic test procedure. Time of sound wave travel, velocity, and dynamic modulus of elasticity can be evaluated with this device. The NDE data resulting from the sonic tests are stored (up to 100 tests) for later retrieval by computer or for printout. The microprocessor-based sonic wave processor is a sophisticated, yet simple-to-use, NDE device for assessing the strength of a group of wood poles in service.

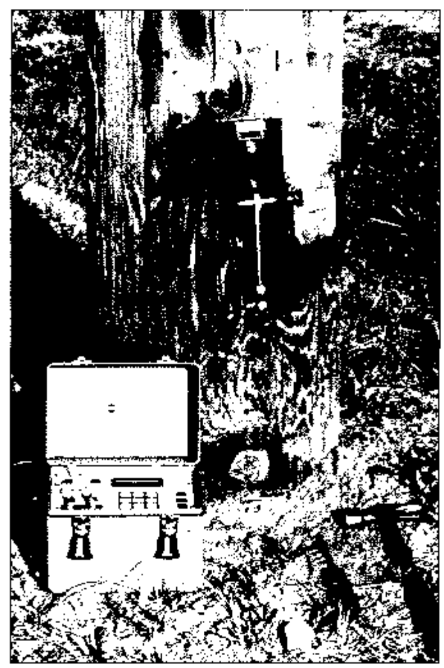


Figure 2 This sonic wave processor for testing the integrity of wood transmission poles is user-friendly and includes a step-by-step procedure; the time of sound wave travel, velocity, and dynamic modulus of elasticity can be measured and evaluated on site.

The second NDE procedure developed, the sonic waveform method, uses the modification of sonic waves as they travel through the wood pole to determine the strength properties of an individual pole. This far more powerful NDE procedure has the potential to accurately grade wood poles according to strength and to rapidly and accurately determine the strength of in-service poles. On the basis of preliminary evaluations, it is reasonable to expect the sonic waveform NDE method will predict the fiber strength of a pole within 500–1000 psi (34–69 MPa). To bring this NDE procedure out of the laboratory requires more correlation effort between the sonic waveform NDE data and test-to-failure data for new wood poles. Additional NDE data, full-scale pole tests to destruction, and correlation effort are required for in-service poles.

Differences in climatic conditions are an important parameter in determining the variation in the strength of a transmission line or pole with time; therefore, calibration data are required to account for local conditions and specific species when a utility uses the time-of-travel NDE method as part of a wood pole management program.

The need of the EPRI project for additional in-service wood pole data in the sonic waveform NDE method and the need of utilities for calibration data in a wood pole management program can both be satisfied with a combined test effort that provides all the data needed by both parties at cost savings for each.

Through Engineering Data Management, Inc., a utility can arrange for in-service poles to be tested to destruction to provide the local calibration data needed by the time-of-travel NDE method. This effort would be part of a utility wood pole management program. As part of the basic pole test, additional measurements and NDE parameters would be recorded for evaluation/correlation in support of the development of the sonic waveform NDE method. The total cost of testing to the utility is $250 per pole, plus the cost of shipping the poles to the Research Institute of Colorado (estimated to be $100 per pole). The utility funding covers the direct cost of testing the wood pole to failure and the acquisition and reduction of data that are necessary to use the time-of-travel NDE method. EPRI funding of approximately $450 per pole supports indirect test cost, acquisition of additional NDE data, and a correlation effort to develop the sonic waveform NDE method.

The immediate benefit to the utility is acquisition of calibration data required to track the strength (reliability) of an in-service line with time. In addition, the utility will have the local calibration data necessary to use the sonic waveform NDE method to determine the fiber strength of individual poles when this method is fully developed. Both benefits to the utility are at the cost of obtaining the local calibration data for the time-of-travel NDE method.

The EPRI goal is to have sufficient new and in-service wood pole correlation data available so that development of commercial sonic waveform NDE hardware can begin near the end of 1985.

RP1352 has made significant progress in developing the documentation, data base, and computer software to implement probability-based design methods for transmission lines. In addition, the project is developing NDE methods to accurately determine the strength of lines and individual poles, which hold the potential of significant cost savings to utilities. *Project Manager: Paul Lyons*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

UTILITY COSTS FROM AIR QUALITY MODELING UNCERTAINTY

Air quality dispersion modeling has been increasingly used in support of regulatory decisions and policies regarding the level of emission control for fossil fuel power plants. Much of this use has stemmed from the statutory requirements established by air quality control agencies for the national, state, and local levels under the Clean Air Act Amendments of 1970 and 1977. Dispersion models as instruments of regulatory policy have provided a quantitative basis for expensive decisions affecting the electric utility industry and its customers, such as determining precise limits on pollutant emissions for a specific point source, the acceptability of a new source in a given area, and emission controls for a wide variety of sources in a region. Uncertainty and a lack of precision in these models have created considerable costs for the utility industry and its customers. To compensate for model uncertainty, utilities have been forced to adopt conservative and costly assumptions and also to collect large quantities of ancillary information. EPRI is sponsoring research to document utility experiences and costs associated with model uncertainty and to suggest where model improvements would be of greatest benefit to the industry and its customers (RP2309).

In most cases EPA-approved Gaussian models are required for use in response to regulatory issues. These models are subject to uncertainties because they do not represent the many complexities actually found in the field. Among the major weaknesses of Gaussian models are that they assume constant meteorologic conditions in both time and space, and they assume uniformity in the wind and dispersion fields.

Because regulatory agencies usually insist that apparent margins of compliance between model predictions and the allowable air quality goal or regulatory limit be positive, the use of a model that may be inappropriate for a particular situation could result in economically inefficient decisions. Further, the required use of approved or regulatory models places a burden on the user to evaluate the performance of nonapproved models, which in some cases may be more appropriate and may suggest a reduced margin of compliance. This often involves extensive and costly air quality and meteorologic field studies. Thus, an issue of important economic concern to utilities is the adequacy of existing regulatory models to describe the dispersion of power plant plumes in areas of rough, complex terrain and during specialized meteorologic conditions.

Project approach

The major focus of RP2309 is the study of utility costs associated with air quality modeling uncertainty. A general objective is to develop data on the costs resulting from regulatory decisions involving modeling (e.g., emission restrictions, control technology) and the costs incurred in evaluating or demonstrating the validity of alternative, more appropriate modeling assumptions or techniques. The project approach is to identify and examine specific uses of dispersion models in regulatory proceedings and to define the nature of modeling uncertainty in each case. The results of this study—based on actual air quality or regulatory proceedings—will be data on the costs to the utility industry and its customers from responding to limited models. In addition, recommendations regarding needed model improvements will be made.

The initial phase of the study has centered on questionnaires and personal communications with utility owners of large sources throughout the United States. The case studies analyzed were limited to utility boiler applications and to point source licensing and permitting proceedings. Questionnaires were distributed to a number of utilities around the country; under a guarantee of anonymity a total of 20 responded with information regarding some 35 individual cases.

The questionnaires and initial contacts were used to screen the cases and to select those in which controversies about model selection or model applications played a key role in the regulatory decision-making process. It was also desired to obtain data on a mix of regulatory issues. Nine cases were selected that involved as wide a variety of regulatory and technical issues as was possible under the circumstances.

On the basis of the information obtained, each situation was classified in terms of the specific regulatory issue in question (e.g., prevention-of-significant-deterioration permit application, state-implementation-plan revision, control technology implementation); the technical modeling issues involved and the topics of modeling controversy; and the costs incurred during the regulatory process and as a result of decisions based on modeling applications. Among the costs considered in this study were expenses for required meteorologic and/or air quality monitoring field studies, modeling and data analysis costs, legal fees, fuel differential costs, the costs of installing pollution control technology or of changing the proposed characteristics or location of a plant, the costs of imposed emission restrictions, and delay costs.

Case study results

Table 1 presents estimates of the costs incurred by the utilities in the nine case studies as a result of modeling uncertainty. To enable meaningful cost comparisons from case to case and between categories, all costs were scaled to 1983 dollars. An analysis of the overall results revealed three cost categories to be the most significant: costs entailed by delays and the use of alternative fuel supplies, costs for field studies and ambient air quality monitoring studies, and costs for air quality dispersion modeling studies.

Costs associated with delays and the use of alternative fuel supplies (e.g., lower-sulfur coal) as a result of emission reductions were the dominant cost factor—running in the tens of millions of dollars. Such costs are un-

Table 1
COSTS ASSOCIATED WITH MODELING UNCERTAINTY FOR NINE CASE STUDIES
(thousands of 1983 dollars)

Cost Category	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	All Cases
Field studies	2,575	0	0	0	0	1,862	583	0	0	5,020
Ambient air quality monitoring	0	0	718	332	42	0	0	704	94	1,890
Meteorologic monitoring	0	0	0	320	0	0	0	0	0	320
Air quality dispersion modeling	0	365	42	6	0	120	72	34	20	659
Model validation studies	0	75	42	0	0	0	0	119	0	236
Other studies	0	0	9	0	0	0	65	0	0	74
Subtotal	2,575	440	811	658	42	1,982	720	857	114	8,199
Delays	0	75,000	0	0	0	0	15,040	0	0	90,040
Fuel differential	0	0	0	0	0	70,000	0	2,000	0	72,000
Total	2,575	75,440	811	658	42	71,982	15,760	2,857	114	170,239

doubtedly the most serious economic consequence of modeling uncertainty. Including within the regulatory framework models more appropriate to such conditions as complex terrain and fumigation would help to eliminate some of the lengthy and costly delays that can result when a source owner must either validate a non-EPA-approved model or demonstrate the inappropriateness of a regulatory model through a field study or an extensive modeling program.

Field study costs were at least an order of magnitude below delay and fuel differential costs. In general, the results on field studies are fairly consistent and suggest that the cost of a field study program can increase substantially in situations with more complex terrain or in situations requiring a large number of sampling locations and a more detailed description of meteorology in terms of space and time.

The costs associated with ambient air quality monitoring studies (Table 2) were generally similar to field study costs. Again, terrain was found to be an important factor: monitoring costs increased markedly in situations involving extremely rough terrain.

In the two cases in which it was necessary to relocate air quality monitors, the resulting costs were similar. In case 3 six monitors were relocated at a total cost of $718,000 ($120,000 per monitor); in case 8 five monitors were relocated at a total cost of $417,000 ($83,000 per monitor). The higher cost per monitor in case 3 can be attributed to the fact that the monitors were relocated to higher terrain during the winter months in order to meet a specific schedule under a consent decree.

The costs associated with air quality modeling were also generally consistent on a case-to-case basis. Although the cost of modeling in a given situation depends on the model applied, the number of receptors involved, the number of years of meteorology modeled, and the choice of various model options, the case study results indicate that modeling costs are typically in the tens of thousands of dollars and are relatively minimal in comparison with other factors. Model validation study costs were similar to the air quality modeling costs.

An effort was made to determine which issues associated with modeling uncertainty were of most importance economically. Although several technical issues surfaced in each of the cases examined, there was generally a dominant issue that governed the course of events in each case.

The findings suggest that over all the cases, plume impingement on elevated terrain was the most important technical modeling issue to the utilities from an economic point of view. There are basically two reasons for the higher costs associated with the plume impingement–complex terrain issue. First, this was clearly the dominant issue in the cases examined in this study. Second, costs for field studies and air quality monitoring programs are significantly increased in complex-terrain situations.

The use of Pasquill-Gifford dispersion parameters for describing the vertical depth and horizontal width of a plume under unstable (Class A) meteorologic conditions represented the next most costly issue. Following

Table 2
AMBIENT AIR QUALITY MONITORING COSTS
(1983 dollars)

Case Number	Number of Monitors	Monitoring Duration (yr)	Total Cost	Cost/Monitor/Yr
4	8	2	$332,000	$21,000
5	1	2.5	$ 42,000	$17,000
8	3	3	$287,000*	$32,000

*Not including monitor relocation costs

this was the issue of fumigation conditions. Costs associated with other issues were relatively insignificant.

The importance of this project has been recognized by the Utility Air Regulatory Group. UARG has referred to findings from the work in its evaluation of the good-engineering-practices stack height regulations recently proposed by EPA.

The development and thorough evaluation of alternative, more appropriate modeling techniques to represent dispersion in situations involving such conditions as complex terrain and fumigation—and the subsequent acceptance of improved models into the regulatory framework—would be instrumental in reducing many of the costs associated with modeling uncertainty, in particular the costs of extensive delays incurred while areas of controversy are debated at length. Although improved models would still be subject to uncertainties, they would nevertheless serve to reduce reliance on the more conservative assumptions and techniques often used to ensure appropriate margins of safety in developing control strategies. *Project Manager: Abraham Silvers*

RAIL ROUTING AND COSTING SYSTEM FOR COAL TRANSPORTATION

Current developments in the U.S. transportation system, including regulatory reform, large-scale railroad mergers, and prospective intermodal ownership, require comprehensive analysis of alternative coal transportation services. This can be a formidable task, particularly for planning and exploratory studies in which the details of prospective coal movements are not sufficiently specified to allow the use of standard costing methods. Also, the data required to evaluate railroad alternatives are not readily available to most coal shippers. To help utilities deal with this situation, EPRI has developed an analytic tool called the Rail Routing and Costing System (RRCS), which is available for trial application on a prerelease basis. The contractors are CACI, Inc.–Federal and the University of Tennessee Transportation Center (RP1219-3).

RRCS is an easy-to-use, computer-based tool for fuel procurement planning. It has many applications—for example, determining likely railroad routings and carrier costs; analyzing railroad mergers; studying the impacts of rail line abandonments; estimating the costs of transporting coal by rail from alternative sources of supply; and obtaining up-to-date information on rail network structure and costs. Although developed primarily for coal transportation, the system can be used to conduct similar analyses for any commodity moved by rail for an electric utility.

RRCS consists of five application modules, a data base shared by these modules, and a system controller that coordinates the activities of each module. The capabilities provided by the modules are shipment routing, rail network management, cost analysis, travel time analysis, and energy use analysis. RRCS is a menu-driven system. It displays a series of menus offering a list of numbered choices. Frequently, a selection will lead to another menu with a new series of choices.

A typical user would begin by selecting the routing module to route and cost one or more coal shipments. After viewing this information, the user might turn to the rail network management module to inspect the individual rail lines covered in the RRCS data base. This module can be used to modify the network to fit any revised data the user has regarding the network. Abandonments, for example, are indicated by simply deleting the appropriate piece of track. The network management module also allows the user to add stations and track to the network and to modify the characteristics of existing network components. After changing the network, the user might return to the shipment routing module and reroute the coal shipments over the modified network. In similar fashion, the user can employ the costing module to modify the economic assumptions that underlie the route and cost determinations.

Module capabilities

The shipment routing module is used to route one or more shipments through the U.S. railway system. The module determines a route for each shipment and calculates several important statistics regarding the route—namely, carrier cost, travel time, energy use, and distance. The module can also produce these statistics for a specific route preselected by the analyst.

The results from the shipment routing module can be displayed at various levels of detail, depending on the reporting format selected. Three formats are available. The first presents the cost and other statistics for the entire route. The second presents these statistics and describes the route by showing stations and carriers. In addition to all this information, the third, most detailed format provides cost, time, energy use, and distance statistics for each segment of the route. Figure 1 shows an ex-

```
COMMODITY:  UNIT-COAL
FROM:       JACOBS JCT,WY
TO:         ST LOUIS,MO
KILOTONS:   950.00

       TOTAL SUMMARY STATISTICS

$/TON       HOURS      KBTU/TON     MILES
_______    ________    ________    _______
18.84       39.0        301.78      1116.

DO YOU WANT TO CONTINUE?  YES

ROUTE TAKEN --

  JACOBS JCT,WY -- (BN,CNW) --  DONKEY CREEK,WY -- (BN,NONE) --
  CRAFORD,NE -- (BN,NONE) -- ALLIANCE,NE -- (BN,NONE) --
  GRAND ISLAND,NE -- (BN,NONE) -- AURORA,NE -- (BN,NONE) --
  SEWARD,NE -- (BN,NONE) -- LINCOLN,NE -- (BN,NONE) --
  TABLE ROCK,NE -- (BN,NONE) -- FALLS CITY,NE -- (BN,NONE) --
  NAPIER,MO -- (BN,NONE) -- ST JOSEPH, MO -- (BN,NONE) --
  CHILLICOTHE,MO -- (BN,NONE) -- BUCKLIN,MO -- (BN,NONE) --
  MARK,MO -- (BN,NONE) -- HANNIBAL,MO -- (BN,NONE) --
  LOUISIANA,MO -- (BN,NONE) -- OLD MONROE,MO -- (BN,NWS) --
  W ALTON,IL -- (BN,NONE) -- ST LOUIS,MO

DO YOU WANT TO CONTINUE?   NO
```

Figure 1 Sample output from the RRCS shipment routing module. In this reporting format, statistics for the entire route are presented and the path taken is displayed. Between each pair of stations the name of the rail carrier that owns the track is given, along with any carrier that has trackage rights. (The word *none* indicates that no other carrier has these rights.) RRCS can also break down the cost and other statistics by route segment if the user needs more detail.

ample of the format with the intermediate level of detail.

A considerable amount of economic and engineering data is used by RRCS in calculating rail transportation costs. Through the cost analysis module the user can inspect these data, along with associated economic assumptions, and make any changes needed to represent more accurately the circumstances of a particular coal movement. The module provides these capabilities for the costs accrued by carriers on track segments, at stations, and at terminals. Changes made by the user are incorporated into the cost factors of the RRCS railroad data base, which are then used by the shipment routing module in developing route and cost information.

In RRCS analyses, routes and costs are based on engineering estimates of the fully allocated costs incurred by railroads rather than on the accounting formulas used in Interstate Commerce Commission proceedings (either Rail Form A or the Uniform Rail Costing System). It is generally recognized that regulatory costs, while having accepted uses, do not necessarily measure economic resources consumed and may not be appropriate for long-term planning. Thus RRCS produces cost information independent from that obtained by other methods. For regulatory or ratemaking applications, RRCS costs should always be used in conjunction with other information.

The travel time module and the energy use module are very similar to the cost module in concept and application. They are used to inspect data, alter parameters, and produce revised estimates for the RRCS railroad data base.

As indicated earlier, the rail network management module enables the user to modify the node and link structure and associated data describing the railroad network. Nodes and links may be added and deleted, and their characteristics may be changed. Menus for inspecting the data base and tracing the network's structure are also provided in this module.

Table 3
CASE STUDY RATE/COST COMPARISONS FOR COAL UNIT TRAINS

Region	Distance (mi)	Rate ($/t)	Cost* ($/t)	Rate/Cost
East	377	14.21	8.55	1.66
	397	14.21	8.86	1.60
	402	13.01	7.86	1.65
	419	14.21	9.45	1.50
	424	14.21	9.55	1.49
	430	14.21	9.68	1.47
	445	14.21	9.88	1.44
	446	14.21	9.58	1.48
	470	15.23	10.39	1.47
	512	15.23	11.24	1.35
	564	14.55	12.13	1.20
	565	14.55	12.15	1.20
	602	15.76	12.95	1.22
	634	15.76	13.63	1.16
South	1310	22.62	18.80	1.20
	1419	22.62	20.26	1.12
	1459	24.33	22.55	1.08
	1649	25.80	25.34	1.02
Midwest	198	10.57	3.77	2.80
	239	6.12	4.99	1.23
	705	10.95	8.90	1.23
	795	14.05	11.79	1.19
	822	12.90	12.08	1.07
	876	13.64	12.87	1.06

Note: Rates and costs are expressed in 1982 dollars.
*RRCS estimate of fully allocated carrier cost.

System applications

RRCS has been used to analyze actual and prospective coal movements for a number of electric utilities. Appalachian, midwestern, and western coal sources were involved in these applications. Nearly all the shipments were by unit train service, and a few represented the rail portion of prospective rail-water moves.

In general, RRCS produced satisfactory routings. For many shipments the model duplicated the current or anticipated route exactly. In several cases the model's selection was affected by recent rail mergers that permit single-carrier routings considerably longer than those formerly available. It is likely that traditional routings will be modified to take advantage of such opportunities.

Without access to private railroad data, it is not possible to validate or verify the origin-destination cost estimates produced by RRCS. However, rate quotations were available for some of the shipments, and these rates were compared with the modeled costs (Table 3). In most cases the ratio of rate to cost lies between 1.0 and 1.66. In fact, for three-fourths of the data, the ratio is between 1.16 and 1.66. These results appear reasonable in view of current utility experience; railroads propose coal rates that more than cover fully allocated costs in order to make up for slimmer (or negative) margins on more competitive traffic. The case study rate/cost ratios decline as the length of haul increases, which is also consistent with observed real-world pricing behavior.

The utilities involved in these RRCS applications used the results as one element of their rail cost analyses. One utility successfully used the results in a state public utility commission hearing to demonstrate its diligence in seeking low-cost coal transportation services.

R&D status

RRCS is operational on a prerelease basis and can be accessed by any utility with a computer terminal and a modem. It can also be accessed through a microcomputer (and modem) equipped with terminal emulation software.

The RRCS costing routines are being modified to use variable costs in addition to fully allocated costs. Detailed cost validation studies are also under way. In support of another EPRI research effort, RRCS is being used to estimate transportation costs for sodium compounds to help assess their feasibility for use in flue gas desulfurization. For the future, consideration is being given to expanding the system to include parallel capabilities for shipments using the inland and intercoastal waterways. A microcomputer version of the system is also a future possibility.

In summary, RRCS provides utility planners with a powerful interactive tool for analyzing rail transportation options. Its principal functions are data base management, shipment routing, and costing of rail routes. Because the system automatically calls up the data editors and application processors needed to follow the user's instructions, the user does not have to construct elaborate job control and data file linkages. This makes it easy for utility fuel supply managers to use RRCS. *Project Manager: Edward Altouney*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

REMOTE SYSTEMS FOR TMI-2 SURVEILLANCE AND CHARACTERIZATION

In areas of major radioactive contamination, such as some areas in TMI-2, reconnaissance by remotely controlled devices is essential. The two most important objectives of such reconnaissance are to video-record the areas that are too contaminated for even time-limited entry by humans and to determine by gamma scans the general level of radioactivity and the hot spots of concentrated contaminants. Sometimes it is also desirable to use gamma spectroscopy to identify which isotopes are present and the intensity of radioactivity at points of particular interest. Investigators study the records of these remotely controlled reconnaissance missions to plan subsequent cleanup and refurbishment.

The Robotics Institute of Carnegie-Mellon University developed a remote reconnaissance vehicle (RRV-1). Two operators control the vehicle from outside the TMI-2 reactor containment building at a console with three television monitors that display what the robot sees in a radioactive area. RRV-1 has three television cameras, strong lights, and radioactivity monitors mounted on a six-wheeled vehicle that is powered and controlled by a special ribbon tether. The tether is tied into cables that penetrate the containment building wall. CMU developed a clever tether management system that plays out the ribbon as the machine moves forward and reels it in as the machine backs up. This system prevents the tether from dragging on the floor and minimizes the probability of its getting tangled or hooked over some object.

GPU Nuclear Corp. used the RRV-1 for the first two reconnaissance missions into the basement of TMI-2. The television pictures and video tapes showed very clearly the situation in the basement. The general background radioactivity was on the order of 30 R/h. A multiple-drawered mechanics tool chest was observed near one wall. This tool chest had been submerged in the highly contaminated water that stood in the basement for many months before it was pumped out through deionizers. Activity at the tool chest was measured at ~200 R/h. The hottest spot monitored was an area of concrete blocks that make up the wall around the elevator shaft. The reading was ~1100 R/h at the "bathtub ring," where contaminants had soaked in the most.

GPU fabricated a high-pressure water spray ring that is used to decontaminate the RRV-1 and its tether as they are raised from the basement through the hatch. This device worked quite well. When it was parked on the 305-ft (93-m) building level above the basement, activity at the RRV-1 was the same as the general background level in the parking area, which was in the range of 40–80 mR/h. During these first two missions into the TMI-2 basement, the RRV-1 was active over two periods totaling 10 hours. In addition, the machine was parked in the basement overnight. The robot and its equipment performed very well.

Researchers have not yet used gamma spectroscopy with the RRV-1. However, they are planning to use a collimated detector, developed by New York University, with a pulse height analyzer to identify the isotopes that are contributing to the radioactivity. DOE and EG&G, Inc., are building a second-generation version of the prototype developed by NYU. These two instruments are designed to operate with two different kinds of detector crystals and two different shield arrangements to obtain best results in different radioactive fields. The detector weighs about 70 lb (32 kg) in the configuration used in fields of 10–500 R/h and about 25 lb (11 kg) for use in fields of <10 R/h. This small size and weight makes the detector more readily adaptable to remote uses. The large collimated gamma scope, used heretofore for spectroscopy at TMI-2, weighs about 700 lb (318 kg) and is transported on a dolly that must be placed and aimed by hand. The new devices will allow spectroscopy in areas inaccessible to the large device. The development of the NYU prototype is reported in NP-3804.

Researchers at the Science Applications, Inc., laboratory in Rockville, Maryland, developed a second gamma detector. This device is a particularly small portable gamma scope that is hermetically sealed; it can be used to take measurements inside pipes (4 in diam and larger) and tanks where fission products and fuel particles have settled after being expelled from the reactor vessel. Personnel can place this small gamma scope in difficult-to-reach sites by pushing the detector along inside the coolant pipes with a flexible cable similar to a plumber's snake. The development and testing of the SAI device is reported in NP-3781.

Two other remotely controlled robots are being developed for use in highly contaminated areas where personnel cannot work efficiently. One is a tether-controlled scabbling machine that will remove the coatings and a 1/16–1/8-in (1.6–3-mm) surface layer of contaminated concrete floors. This machine incorporates a vacuum and filter system to collect the loosened radioactive debris.

The other device is a radio-controlled remote work vehicle (RWV) that will have a manipulator arm and special tools for scrubbing contaminants from walls and other surfaces. The RWV will have more space and capacity for specialized tools than does the RRV-1 with its tether and tether management system. The new radio control system should overcome problems with radio signals the RRV-1 encountered in the reactor containment building. The RWV will operate in conjunction with RRV-1, which will be the eyes and ears for operations to be accomplished by the RWV. *Project Manager: R. K. Winkleblack*

PRECONDITIONING BWR PIPING

Several utilities are replacing BWR recirculation piping systems damaged by intergranular stress corrosion cracking (IGSCC). Experience has shown that new pipe surfaces become contaminated quickly during initial exposure to reactor water unless they are pre-

conditioned. EPRI has field-tested and qualified electropolishing and preoxidation processes that modify pipe interior surfaces and greatly reduce radioisotope deposition.

IGSCC problems are causing several utilities to replace recirculation piping systems in their BWR plants (*EPRI Journal*, September 1984, p. 14). The new piping is typically type-316 nuclear-grade stainless steel. In 1983 Nine Mile Point became the first plant to undergo a major piping replacement program. After only 0.75 effective full-power year of subsequent operation, radiation fields on much of the new piping were as high as they had been after 10 years of previous operation. This piping had been sandblasted after manufacture. Interestingly, radiation fields on piping from another manufacturer, which had not been sandblasted, were much lower, indicating the importance of surface finish and the potential benefits that could be obtained by surface modification.

EPRI has investigated three main methods of reducing recontamination: electropolishing, preservice filming, and chemical passivation. Because of the urgent need to implement preconditioning technology, EPRI adopted a two-phase approach. In phase 1, EPRI field-tested electropolishing and prefilming techniques, which showed no deleterious effects on the stainless steel. This work began in June 1983 and was completed in October 1984. Each process is estimated to reduce the recontamination rate by a factor of 2; when used together, the processes may improve the recontamination rate by a factor of 3. The second phase of the project began in 1984 and continues at this time. This phase focuses on developing and field-testing new chemical passivation techniques that promise to yield even greater benefits. However, substantial development will be necessary before these techniques will be available for application.

Electropolishing

Plant loop tests carried out under RP819-1 showed that the deposition of cobalt-60, the radioisotope mainly responsible for piping radiation fields, was proportional to surface roughness. Electropolishing removes surface ridges, protrusions, and other imperfections that trap cobalt-60 circulating in the coolant water. However, because electropolishing is often used to etch grain boundaries for metallographic examination and the same type of intergranular attack (IGA) is a precursor to stress corrosion cracking, some industry experts have expressed concern that this process might make the stainless steel more susceptible to IGSCC in subsequent service.

To address these issues Quadrex Corp. electropolished a 12-in-diam type-316 nuclear-grade pipe, including welds and an elbow, using a range of conditions (temperature, current density, and duration) encompassing the process parameter variations anticipated in plant applications. This work is reported in EPRI NP-3832. The pipe was shipped to General Electric Co. for metallographic examination and IGSCC testing, using constant extension rate and crevice bent beam tests in simulated BWR water chemistry. Investigators found no IGA and no increase in susceptibility to IGSCC. In fact, the electropolishing process had removed IGA caused during pipe manufacture (Figure 1), and the improved finish will probably increase long-term resistance to IGSCC (NP-3833).

Profilometer measurements of the surface roughness showed that electropolishing reduced the surface roughness from about 250 μin (6.35 μm) in the as-fabricated pipe to about half that value. Mechanical honing methods to reduce the roughness of as-fabricated pipe appear feasible for field applications and are being considered as a processing step before electropolishing. Quadrex applied the electropolishing process to new piping before installation at the Monticello plant in mid 1984, and several other utilities are also specifying electropolishing for replacement piping.

Preoxidation

The deposition of soluble cobalt-60 on stainless steel occurs by absorption of the cobalt in the growing oxide film. In fact, the deposition rate is approximately proportional to the oxidation rate. A fresh stainless steel surface oxidizes rapidly for the first few hundred hours in high-temperature water until a protective oxide film forms. When a fresh surface is placed in an old plant that already has cobalt-60 in the coolant, the initial contamination rate will be rapid.

Applying a protective oxide film before exposure to reactor water can greatly reduce the

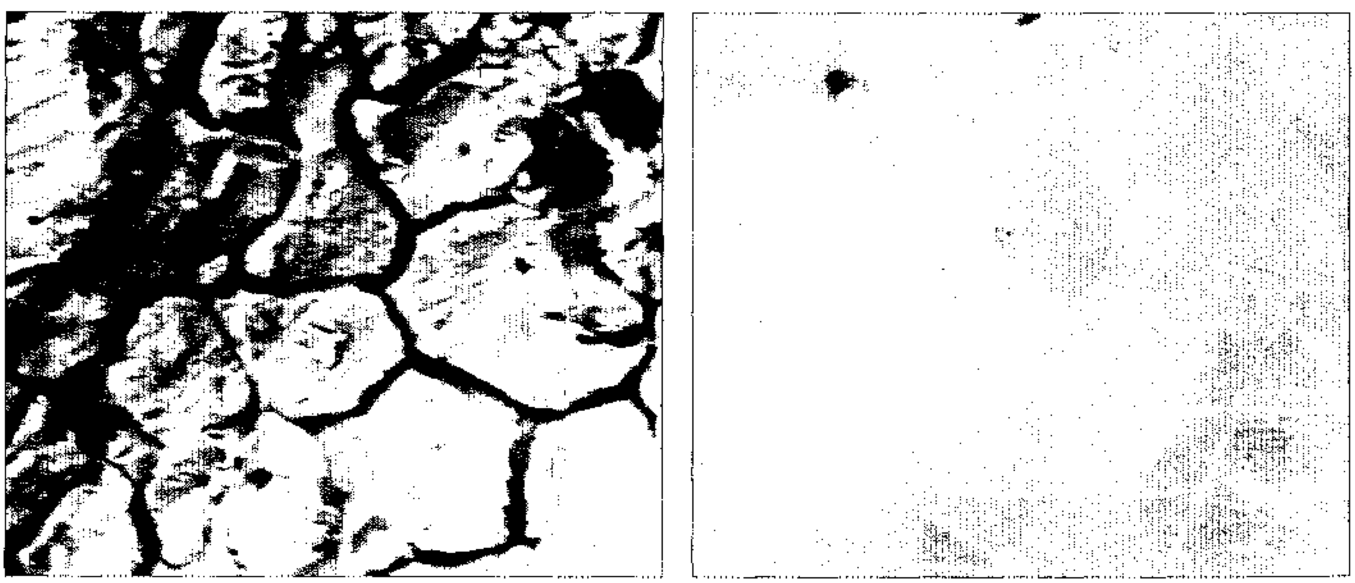
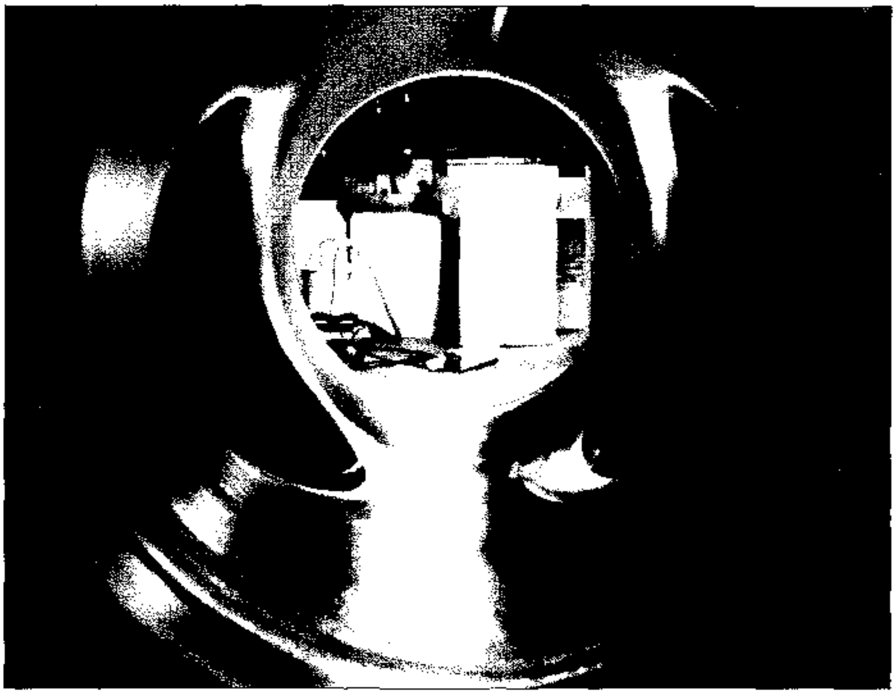


Figure 1 Scanning electron microscopy shows the topography of pipe interior surfaces before and after electropolishing: (left) the as-received surface, (right) after polishing for 24 minutes. Both micrographs have been magnified 500 times.

rate of cobalt deposition. The film can be applied by using the reactor coolant pumps to circulate high-temperature oxygenated water before the plant returns to power. However, the process takes several weeks of in-line time, which results in a heavy cost penalty. As reported by J. Blok to the 1984 ANS Executive Conference on Decontamination, tests in a loop at its Cooper plant by Radiological and Chemical Technology, Inc. (RCT), demonstrated that an air preoxidation process was very effective. This process resulted in similar cobalt deposition rates for oxygenated water when tested in loops at Vallecitos Nuclear Center by General Electric (RP2295-3).

The air oxidation process is applied at atmospheric pressure, which means that it can be conveniently applied to lengths of pipe before installation and save several critical days' time. To qualify processes of this type, EPRI sponsored a full-scale field test by Quadrex, which demonstrated that a uniform, coherent oxide film could be applied to complex pipe geometries, as shown in Figure 2 (NP-3832). Subsequent tests by General Electric showed no increase in IGSCC susceptibility (NP-3833). The RCT preoxidation technique has been applied to electropolished replacement piping for the Cooper plant, and a number of other utilities are considering a similar approach.

Figure 2 Interior surface of electropolished and preoxidized BWR piping, showing a uniform oxide film.



Chemical passivation

The EPRI program now focuses on developing chemical preservice treatments to passivate or inhibit corrosion of stainless steel, because reducing corrosion will likely minimize cobalt pickup. One approach is to dope the growing oxide film with small quantities of soluble zinc; work by General Electric under RP819-2 has shown that zinc is a powerful corrosion inhibitor. Initial loop test results suggest that the process also reduces cobalt deposition, and work to optimize the process is proceeding.

Other methods under study include use of chelating agents, such as ethylenediaminetetraacetic acid (EDTA), which have proved effective in other reactor systems, and chromizing processes used to reduce corrosion in fossil fuel plants. These and other promising techniques will be tested in the Vallecitos loops during 1985. EPRI also plans tests under PWR conditions; some of these processes may be effective preconditioning techniques for steam generators before plants enter service. *Project Manager: C. J. Wood*

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