Mapping Magnetic Fields

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Cover: Special measurement equipment at EPRI's Magnetic Field Research Facility allows scientists to record the spatial variability of magnetic fields and plot the results three-dimensionally. In this plot of fields measured in a kitchen, the highest levels show up around the stove, near an analog-type clock, and in the far corner, where the electric service connection is located on the outside wall.

Looking Ahead on EMF

In today's wired-up world, most of us are exposed to varying degrees of low-frequency electromagnetic fields from sources as common as home appliances and house wiring all the way to the obvious utility power transmission or distribution lines. Unraveling an individual's exposure from all these sources is a complex task, one which EPRI is making a substantial contribution toward completing in a national survey of residential magnetic fields and in other, related exposure assessment projects. The work is part of a broad, $6-million-a-year research effort on EMF that includes epidemiologic and laboratory studies aimed at getting to the bottom of the health effects issue.

But the electric utility industry's research agenda is not set in an ideal world in which answers to questions are always pursued in a logical progression from the certain establishment of facts and knowledge. Public concern about possible health effects from exposure to EMF is creating pressure and expectation for measures to reduce or eliminate such fields before a scientific understanding of the nature and magnitude of the risk is in hand. In several states, utilities are being asked by regulators to identify measures that could be taken to reduce magnetic fields around utility sources if the biomedical research evidence eventually indicates a need to limit public exposure to magnetic fields.

It is in response to these developments that EPRI has begun some engineering analysis and research on magnetic field management. This work is centered in the Electrical Systems Division but also includes related studies on end-use equipment directed by the Customer Systems Division. Our immediate goal is to gather and provide the technical information that utilities need to respond to regulatory inquiries about magnetic field management; we also aim to provide whatever additional research capabilities are needed, should it become necessary to actually implement measures to manage magnetic fields.

Because of the variety and pervasiveness of magnetic field sources, field management may take several forms and approaches. It is essential that we understand the comparative costs, safety implications, and potential degrees of exposure reduction of all the possibilities. Because we can bring to bear a unique array of power system research facilities and a long-established body of technical expertise and information, EPRI is uniquely qualified and equipped to explore the technical options for magnetic field management. Related projects already under way or planned whose anticipated results could play a role in magnetic field management have a combined contract value of over $7.5 million. While EPRI's and the industry's power systems engineers continue to cast an anxious eye to the biological sciences for a clear bottom line on health effects, we are confident that engineering can rise to whatever challenge we are ultimately given in the matter of magnetic field management.

Narain G. Hingorani, Vice President
Electrical Systems Division

RESEARCH UPDATE

DEPARTMENTS

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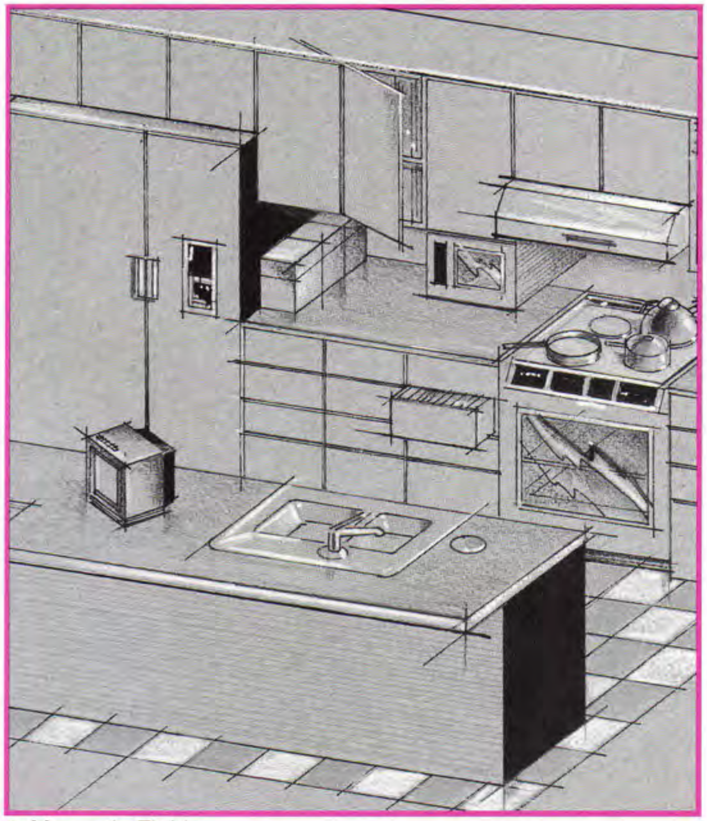
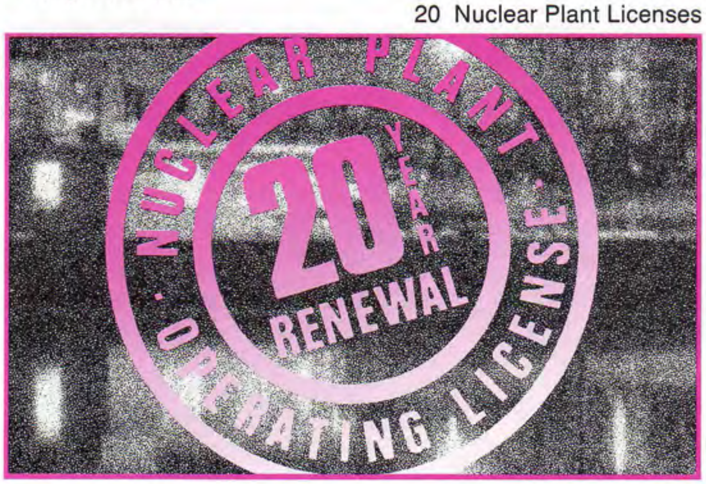
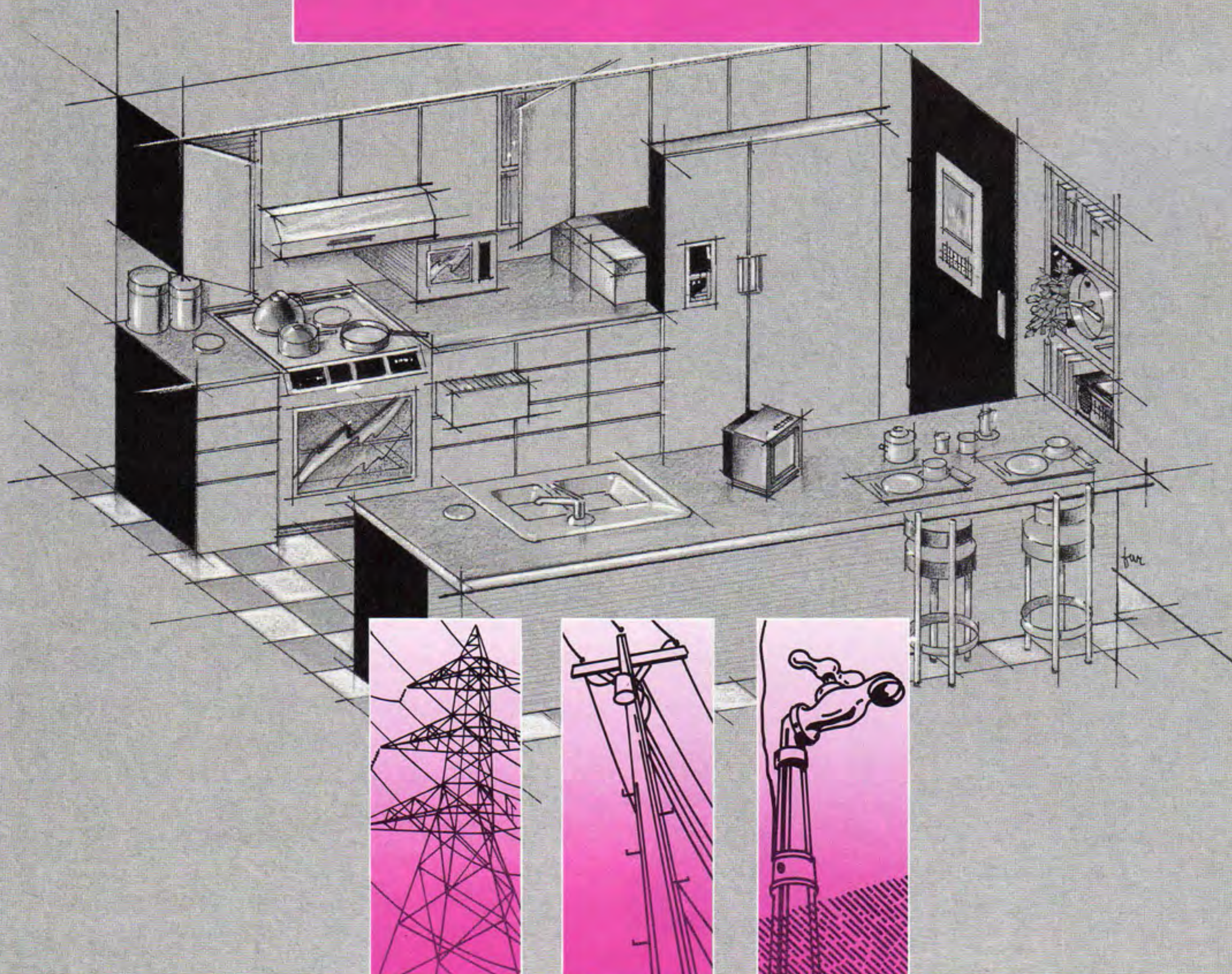


4 Magnetic Fields

20 Nuclear Plant Licenses



Exploring the Options for Magnetic Field Management



Science is being urgently pressed to answer whether exposure to electromagnetic fields (EMF), such as occur around power lines as well as house wiring, electrical machinery, and home appliances, may be linked to certain forms of cancer. But some electric utilities and companies in other industries, reflecting public concern, are already beginning to explore ways of reducing exposure to these fields before the scientific verdict about health risks is in.

At stake potentially, as noted recently by one government official, is the rewiring of America and the redesign of almost anything electrical, at possibly great cost to consumers, manufacturers, and utilities. But to many scientists investigating the biomedical evidence on EMF, any move now to reduce exposures is placing the cart before the horse. It would fly in the face of standard regulatory practice for limiting environmental health risks, which is based on a knowledge of a dose-response relationship and a mechanistic understanding of how something causes cancer or disease. In the case of EMF, neither of these factors has yet been determined.

Last June the Environmental Protection Agency cited these key unknowns in characterizing EMF as a "possible, but not proven, cause of cancer in people." In a draft report, the agency said changes in public policy now would be premature. "We don't really understand the risk well enough to know whether one exists, and we can't give guidance as to what types of avoidance techniques really would be important," said William Farland, the EPA's director of health and environmental assessment, in a later radio interview. The EPA report, summarizing a two-year review of EMF health studies, is seen by some as a prelude to a new, multiyear federal research effort being considered in Congress.

According to published reports, for some knowledgeable observers there is sufficient suggestion of risks to warrant

THE STORY IN BRIEF

With public concern mounting about possible health risks from exposure to magnetic fields, some utilities are beginning to explore ways of reducing such exposures before the biomedical verdict is clear. Magnetic fields are produced by a number of sources, from transmission and distribution lines to consumer appliances, wall wiring, and even the water pipes or structural steel used as ground connections in many homes and commercial buildings. Although concepts exist for ways to reduce many of these fields, there is considerable uncertainty about the cost and the safety implications of applying such measures. EPRI has recently begun new engineering studies of magnetic field management for various sources and is enlisting several of its unique R&D centers to explore key technical questions relating to fields from transmission lines, distribution systems, wiring practices, and end-use equipment.

efforts now to begin to consider exposure standards and measures to manage magnetic fields. Some prominent members of the Institute of Electrical and Electronics Engineers have called for such standards, and a working group of IEEE's Standards Coordinating Committee 28 (the committee on nonionizing radiation) reportedly is struggling with how to approach setting exposure standards as well as whether to issue guidelines for limiting magnetic fields.

Some manufacturers of products identified as potential sources of significant magnetic field exposure are already implementing design changes to reduce fields. IBM and several other computer equipment makers now offer video terminals designed to cancel much of the magnetic field typically generated by computer monitors. And at least two large manufacturers of electric blankets have altered the internal wiring of their products to dramatically reduce the previously substantial magnetic field.

Other changes are not likely to come as easily. As one moves beyond common consumer appliances to machines and equipment powered by electric motors of various sizes, to utility transmission and distribution systems that carry large amounts of current, and to the wiring built into existing structures, changes to reduce magnetic fields become more complicated, difficult, and costly.

This is not to say there are no options that might help reduce magnetic field exposures. An EPRI R&D planning workshop held last April explored a number of concepts for reducing fields around high-voltage transmission lines, around high-current distribution lines, and even within homes and businesses. But for most such measures, there is significant uncertainty about both the cost and the potential effects in terms of safety. And there remain fundamental questions about the degree of field reduction achievable with various options and how those reductions might relate to as-yet unknown threshold levels or mechanisms for harmful effects from EMF exposure.

EPRI has recently expanded its multimillion-dollar research program on EMF health effects and exposure assessment to include new studies of the engineering challenges posed by a potential need to manage magnetic fields from various sources. The Institute is enlisting several of its unique R&D centers around the country to explore and answer key technical questions relating to overhead and underground transmission lines, distribution systems and substations, residential and other structures—even end-use equipment. Alliances with key electrical manufacturing industries are being pursued. EPRI is also exploring possibilities for new techniques and equipment to limit magnetic field exposures of power line maintenance workers and other utility personnel.

"Electric utilities need to know what the options are for managing magnetic fields, so that if and when science tells us there is a need to reduce them, we will have some idea of what can be done reasonably and cost-effectively," says Narain Hingorani, EPRI's vice president for electrical systems. "To be prepared with that kind of knowledge, we also need some lead time to conduct tests and experiments. Some of the options involve technologies in which EPRI has long been active, but now we must reexamine some of that work from a field management perspective and, in some cases, accelerate it."

The challenge of managing uncertain risk

Researchers at EPRI and elsewhere who are beginning to consider ideas for managing magnetic fields are acutely aware of the constraints imposed by uncertainties that still cloud much of what is understood about possible health effects. For now, the only guiding assumption is that if exposure to magnetic fields may be harmful, stronger fields logically must be of more concern than weak fields.

But even that premise is controversial. The epidemiologic studies that first focused concern on magnetic fields involved average flux densities measured indoors of only 2–3 milligauss (mG). Yet there are numerous high-field sources to which people are commonly, albeit usually only briefly, exposed that generate fields of tens or hundreds of milligauss or more. Intensity is only one of several aspects of magnetic fields that science cannot yet say are either biologically important or irrelevant.

Such aspects—any or all of which might play a role in how magnetic fields cause harm, if they do—also include time (chronic, long-term exposure to low, background levels versus momentary exposure spikes around high-field sources); frequency and harmonics (the relatively harmonic-free 60-Hz fields typical of transmission lines versus the sometimes high harmonic content of fields associated with distribution lines and customer loads); and even the orientation of an alternating magnetic field in relation to the earth's static dc geomagnetic field (which ranges between 250 mG and 600 mG, depending on distance from the poles).

"First of all, we don't know what an effective dose for exposure to magnetic field is, if any; but when you begin to consider some of these additional factors that we don't understand well, the difficulty of identifying what exposures are relevant is compounded even further," notes Stan Sussman, a project manager in EPRI's Environment Division who directs work on exposure assessment and instrumentation. "This says that simply reducing magnetic fields may not be effective."

Sussman notes a further consideration that differentiates human exposure from field sources. "We should probably be less concerned with sources that may produce significant fields but do not involve exposure of large numbers of people than we should be with sources to which more people are commonly ex-

Key Uncertainties Constrain Field Management Options

Researchers are beginning to explore options for reducing human exposure to magnetic fields. But finding the most effective engineering approaches to such management will require further insights into the nature and mechanisms of health effects, if any, resulting from exposure. At least four basic uncertainties are under continuing, intensive laboratory and epidemiologic study; any of these could change the focus of future field management strategy.

Intensity Human exposures can span several orders of magnitude in field intensity. Some epidemiologic studies that have suggested a link between magnetic field exposure and certain forms of cancer involved field levels of only 2–3 mG. Yet many common sources of exposure are known to produce field intensities of tens or hundreds of milligauss, even several gauss. There is no known threshold level for biological effect, and the relationship between intensity and effects is not known.

Time Also far from understood is the importance of the duration of exposure. Are low-level, but chronic, background magnetic fields more, less, or equally important biologically, compared with brief periods of exposure to much stronger magnetic fields? The answer to this question would have a major influence on strategies to limit human exposures.

Frequency Magnetic fields associated with power lines or other sources powered by alternating current change in direction and intensity 60 times a second in step with the 60-Hz (U.S.) utility power frequency. Some biomedical research suggests that magnetic fields can affect biological systems only at certain bands, or windows, of frequency or at particular combinations of frequency and intensity. Harmonics of the 60-Hz frequency, created by the nature of certain customer loads, may also play a crucial role.

Orientation One hypothesis related to frequency is that ac magnetic fields may interact with biological systems on the cellular level if the field frequency is in tune with the resonant frequency of certain cellular ions within the mostly static (nonalternating) dc magnetic field of the earth itself. The geomagnetic field ranges between 250 and 600 mG, depending on distance from the poles. According to this model, the direction of the ac fields must be parallel to the earth's dc field to be biologically effective.

posed. This suggests, for example, that reducing magnetic fields around transmission lines may not reduce most people's exposure much because they do not live close enough to transmission lines for those to contribute substantially to overall exposure. The focus should be on reducing exposures, not just reducing fields." Assessing the intensity and patterns of magnetic field exposure of different groups of people is a major element in many of the epidemiologic investigations of EMF health risks, including research sponsored by EPRI's Environment Division.

Electrical Systems Vice President Hingorani acknowledges that the potential challenge of managing magnetic fields is complicated by the lack of essential information logically linking health effects with exposure dose: "We know the biomedical science is going to take a while, which makes the situation tricky for engineering research. In the case of most health risks, it's at least understood how effects increase with dosage. With magnetic fields, we don't really know if a low field or a high field is of most concern, so we can't simply take a blanket approach and try to reduce all fields below some level—which is also unknown."

Hingorani says EPRI is pursuing a responsible course in marshaling information and insight so that utilities and regulatory agencies can respond to the developing scientific knowledge about EMF from as informed a perspective as possible. "Utilities realize they can't simply wait until science has completely weighed in on the health effects questions, because by then misinformation and emotion may have already determined public opinion and regulation," he adds.

In a sense, utility interest in assessing options for magnetic field management reflects an incorporation of the prudence part of the strategy of prudent avoidance of field exposure, a strategy suggested by a leading group of experts on the EMF issue. M. Granger Morgan, who heads Carnegie-Mellon University's Department of Engineering and Public Policy, and his colleagues outlined this approach to EMF risk management first in a 1988 article in *Public Utilities Fortnightly* and later in a 1989 background paper on EMF for Congress's Office of Technology Assessment.

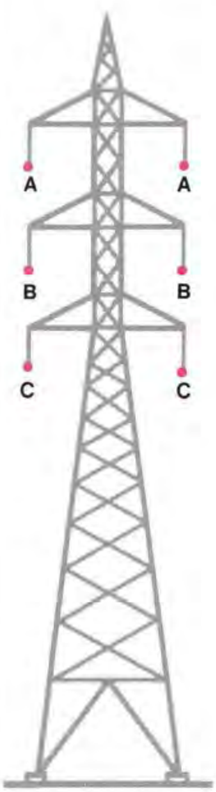
Essentially, prudent avoidance proposes that individuals or society first take only those measures to avoid magnetic field exposures that entail little or modest cost and appear to be prudent, given the current level of scientific understanding about health risks. The Carnegie-Mellon researchers and others have suggested that such measures for individuals might include avoiding the use of (most) electric blankets and sitting back a bit from a computer monitor.

Some proponents have gone so far as to suggest that, for society at large, prudent avoidance could mean widening transmission line rights-of-way (ROW) and rerouting new lines to avoid areas where people live or work; developing new designs for utility distribution systems, including new low-voltage (secondary) grounding procedures, to minimize associated magnetic fields; similarly, developing new approaches to house wiring; and redesigning appliances to minimize or eliminate fields. Many experts, however, would argue that such measures in fact represent quite drastic steps. The cost of even a few of them, broadly applied, would be substantial, they say.

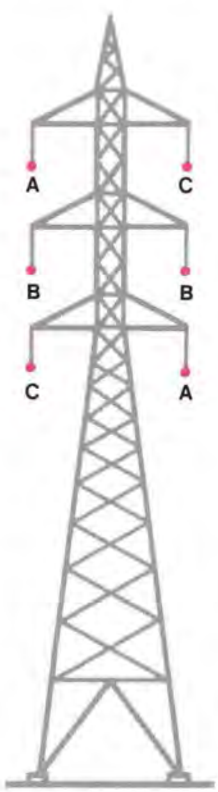
But as the framers of prudent avoidance noted from the outset, the strategy's effective implementation must be accompanied by behavioral, political, and perhaps even legal changes to reduce questions of liability and responsibility that can impede voluntary efforts to manage such an uncertain and largely undefined risk as EMF exposure. For example, manufacturers who redesign products to re-

Low-Field Transmission Line Configurations

Different designs for conductor spacing and phase arrangements can have markedly different magnetic fields. Until recently, design choice was dependent primarily on such operational criteria as a line's capacitance and reactance or on such environmental criteria as visual aesthetics or corona discharge, which can cause audible noise or radio-frequency interference.

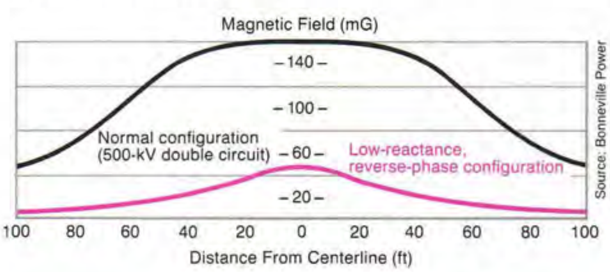


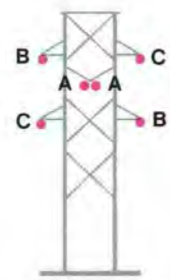
Typical double circuit



Low-field, low-reactance, reverse-phase configuration

Low reactance, reverse phase A typical double circuit with A, B, C phasing on both sets of conductors can be converted to a reverse-phase design—in which one circuit's conductors are phased C, B, A—to substantially cancel much of the line's magnetic field. This option essentially involves changing the conductor bus connections at the substation, assuming the station layout will permit the rearrangement. An existing single circuit could be upgraded to a double circuit with reverse phasing, but that would involve tower modifications.





Split phase This variation of reverse phasing for double circuits brings the A phase conductors for both circuits close together and reverses the phasing of B and C conductors on the outside of a structure to substantially reduce the magnetic field, compared with a typical double circuit. Tower modifications would be required for upgrading an existing single circuit.

duce magnetic fields fear inviting lawsuits from people who perceive that a redesigned, low-field product confirms a risk with the original equipment.

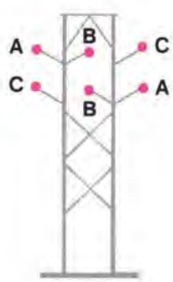
The prudent avoidance strategy seems to be striking a responsive chord among many members of the public, politicians, state utility regulatory commissions, and, consequently, even some utilities and other affected industries. Some people suggest that prudent avoidance is a cautious, conservative approach to possible EMF health risks that is justified, given the large uncertainties. According to critics of the strategy, however, it dangerously suggests a perception of risk that is not justified by the available biomedical evidence, and it will lead to unnecessary, expensive, and possibly even counterproductive measures to reduce magnetic field exposures.

Prudent avoidance is being broadly interpreted in some quarters to include other public policy responses that may not materially reduce or change most people's EMF exposure levels or patterns. Regulatory agencies in Florida, New Jersey, and New York have already adopted or proposed magnetic field limits along transmission line rights-of-way. Some are considering specific requirements for new lines, such as underground construction, and are even considering applying the regulatory concept of keeping exposures as low as reasonably achievable (known by the acronym ALARA), borrowed from the field of nuclear radiation protection.

In an effort to be responsive to public concern about magnetic field exposures, utility regulators are beginning to set field limits for power lines that, initially at least, approximate the field levels measured for circuits of various voltage ratings in actual use under maximum current loadings. But regulators are already assessing whether those limits are adequate, and some have asked utilities to evaluate and report on options for actually lowering magnetic fields from typical levels.

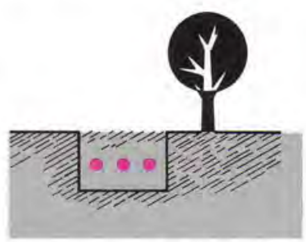
Now, utility and EPRI engineers are reviewing design options that satisfy these important design criteria but also feature reduced magnetic fields. Some options may be best suited for application when new lines are constructed; others might be applied as part of upgrading an existing line.

Delta configuration For new lines using lattice towers, the central conductor can be raised above the outside two in a regular delta configuration to achieve some measure of magnetic field cancellation. There is also an inverted delta design, proposed for use in Sweden, in which the outside conductors are raised above the center one. This requires a substantially different tower design.

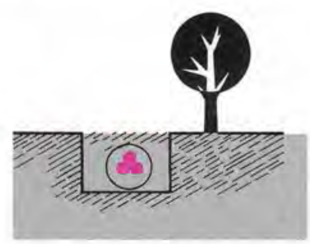


Compaction An existing single circuit can be upgraded to a compact double circuit through tower modifications and the use of special double-ended insulators or angled insulators (as shown). Compaction to the maximum degree possible, given environmental conditions and the need to avoid corona discharge, can significantly reduce the double circuit's magnetic field. The upgraded double circuit could also be reverse-phased to achieve an even greater reduction of magnetic field.

Modest field cancellation



Substantial field cancellation



Underground transmission While the earth around underground lines provides no shielding against magnetic fields, near-total cancellation of a field can be achieved when the three phase conductors of transmission lines are very closely spaced within an oil-filled, steel pipe enclosure. This is not necessarily the case with direct-buried conductors, however, where the field reduction effect of close conductor spacing may be negated by the transmission line's proximity to people. (In the case of single-phase distribution lines, undergrounding may even result in an increased magnetic field because of potentially higher net currents.) The cost of underground transmission line construction can be very high, depending on location and circumstances, and the option has traditionally been used only in dense urban areas where overhead high-voltage lines are otherwise impractical.

Line configurations to minimize fields

High-voltage lines for bulk power transmission—operating at several ratings ranging from 115 kV up to 765 kV—are a key focus of regulatory and research attention for magnetic field management. This does not so much reflect the actual contribution the lines make to most people's overall magnetic field exposure (fields can be high but decline rapidly with distance) as it reflects the public's perception of them as a high-field source. In some cases, fear and concern about these lines even predated evidence implicating magnetic fields with health effects.

New transmission lines cost $750,000 or more per mile to install, and litigation seeking to remove or reroute them or to block construction because of EMF concern has meant their high visibility can add to their already high cost. Some utilities now include EMF and proximity to people as one of several factors they consider in siting new power lines. This complicates even more the difficult engineering design trade-offs involving such other environmental factors as height, corona losses, audible noise, and radio-frequency interference.

Numerous tower and circuit configurations are employed by utilities for the heavy, three-phase conductors used in high-voltage transmission. There are lattice, H-frame, pole, and guyed towers and single circuits, double circuits, and bundled or compact circuits with different phase arrangements. Engineers have long observed and analyzed how the electric and magnetic fields can vary around different mechanical and electrical line configurations. A great deal of such technical knowledge has been gathered and documented for utilities for more than a decade at EPRI's High Voltage Transmission Research Center (HVTRC), operated by General Electric at Lenox, Massachusetts.

For any power line, electric fields vary in intensity as a function of voltage and line configuration, while magnetic fields are a function of the amount of current flowing in the conductor. A high-voltage circuit carrying the same amount of power as a lower-voltage one would have a lower magnetic field, assuming current flows were balanced between phases. Although some people have suggested simply increasing the voltages used for transmission (and, by implication, in substations) to reduce magnetic fields, EPRI research managers point out that this would entail redesigning and replacing virtually every major piece of equipment involved in bulk power transmission. And as current flows increased with normal load growth, magnetic fields would inevitably begin to approach the previous levels experienced at lower voltages.

It has long been known that different circuit configurations create substantially different magnetic fields at the centerline or at the edge-of-ROW. The more closely conductors can be spaced, the lower the magnetic field will be. This, in turn, will increase the potential for corona discharge, radio interference, and audible noise, which is greater at higher electric field intensities. The arrangement of the A, B, and C phases in typical three-phase transmission also can be optimized to cancel part of a circuit's magnetic field more than a few feet away. But until recently this information was largely incidental to design criteria that focused on such other electrical characteristics as corona losses and flashover potential; radio interference and audible noise; capacitance and reactance; lightning-forced-outage rate; and inductive coupling to nearby pipelines, railroad signals, and communications circuits.

Some utilities use a low-reactance, reverse-phase configuration for double circuits because it offers certain desired operational characteristics. But the design also turns out to offer magnetic field reductions of 50% or more, compared with similar circuits with conventional phasing. Vertically arranged conductors on one side of a tower are phased A, B, C from top to bottom, as is typical for most circuits, while those strung from the other side are phased C, B, A.

Both circuits must be connected to the same buses at either end so that current flows are balanced, but the approach basically involves changing the phase connections at the substation. The effect is that the alternating, phased magnetic fields of one circuit are substantially canceled by the oppositely phased fields of the other circuit. In addition to such reverse phasing, there are also concepts for split-phase arrangements or phase interleaving that tend to cancel out much of a circuit's magnetic field. EPRI's Hingorani cautions that some of these concepts could have drawbacks such as higher cost and lower reliability because of the difficult trade-offs with other environmental factors.

Richard Kennon, EPRI's program manager for overhead transmission lines, calls the low-reactance configuration probably the most attractive option, either for new lines or for upgrading an existing single circuit if more capacity is needed. "You can double the capacity of a line while reducing the magnetic field by half," says Kennon. "For a new line, it involves very little cost differential, but for upgrading an existing line, you'd have to reanalyze the structural loading from the additional conductors on the towers to see whether their design would, in fact, allow adding a circuit."

Most single-circuit transmission lines arrange the three phase conductors in a flat configuration when using H-frame or lattice towers. But it's known that a delta configuration, which elevates the center phase conductor above the outside two in a triangular arrangement, can result in a significantly lower magnetic field under or beyond the line. The same is true for an inverted delta—elevating the two outside phase conductors—such as has been proposed for use in Sweden. Kennon says that such designs, involving reconductoring and tower modifications, would probably be difficult to justify for existing lines. But for a new line, the added cost of stronger towers might be minimal. A delta configuration might also allow a circuit to fit within a narrower right-of-way and still meet a nominal edge-of-ROW magnetic field limit.

A third-priority option for transmission lines, says Kennon, is the use of compact designs, which have been developed and implemented over the years to allow more circuits in an existing ROW and sometimes to reduce a line's visual impact. Kennon notes that EPRI studies and tests have shown that reducing the spacing between conductors by 25% can reduce the magnetic field by as much or more. But he adds that because utilities already use differing degrees of compaction, the amount of magnetic field reduction possible will vary as well. One criterion that limits the degree of compaction in some locations is the potential for ice and snow to build up and cause a short circuit.

For all such low-field transmission line configurations, Kennon cautions, there is a risk of increasing the potential for corona discharge, which can cause undesirable audible noise as well as radio-frequency interference. Also, the conductors and insulators must continue to be accessible and safe for maintenance personnel. Analyses of the trade-offs of line designs with lower magnetic fields can be performed with the help of the EPRI TLWorkstation software package, which includes a program (ENVIRO) that calculates magnetic fields for any specified conductor or circuit.

Another possibility for increasing the power capacity of overhead lines while maintaining acceptable environmental parameters is the use of high phase order (HPO) transmission—employing 6 or even 12 phase conductors rather than the standard 3. The technology for HPO transmission has been developed and tested over the years under government and industry research programs as a way of maximizing power transmission capability through existing ROWs or narrower ROWs.

The U.S. Department of Energy (DOE), New York's Empire State Electric Energy Research Corp. (ESEERCO), and the New York State Energy Research and Development Authority (NYSERDA) have sponsored experimental testing of 6- and 12-phase transmission lines for a number of years. Researchers involved in the work recently reported magnetic field measurements, as well as the verification of predictive methods for determining the magnetic fields around such lines. As part of its emerging program for magnetic field management, EPRI is joining with ESEERCO to cosponsor a follow-on project to their earlier work with DOE and NYSERDA to design and operate a 6-phase HPO transmission line as part of the New York State Electric & Gas grid.

EPRI also is cofunding work at ESEERCO to develop a technical information database on 60-Hz magnetic fields associated with a wide range of sources, including transmission and distribution lines, building wiring and grounding, appliances, and electric transit systems. Herbert Kaufman, an ESEERCO program manager, calls the one-year project a "search to draw together technical information from all available sources in a document that will give the utility industry and the public a good idea of what the field levels of various sources are, as well as identify possible methods to reduce fields." The ESEERCO effort, including a measurement survey last year of magnetic fields around New York's high-voltage transmission lines, was begun at the request of the state Public Service Commission.

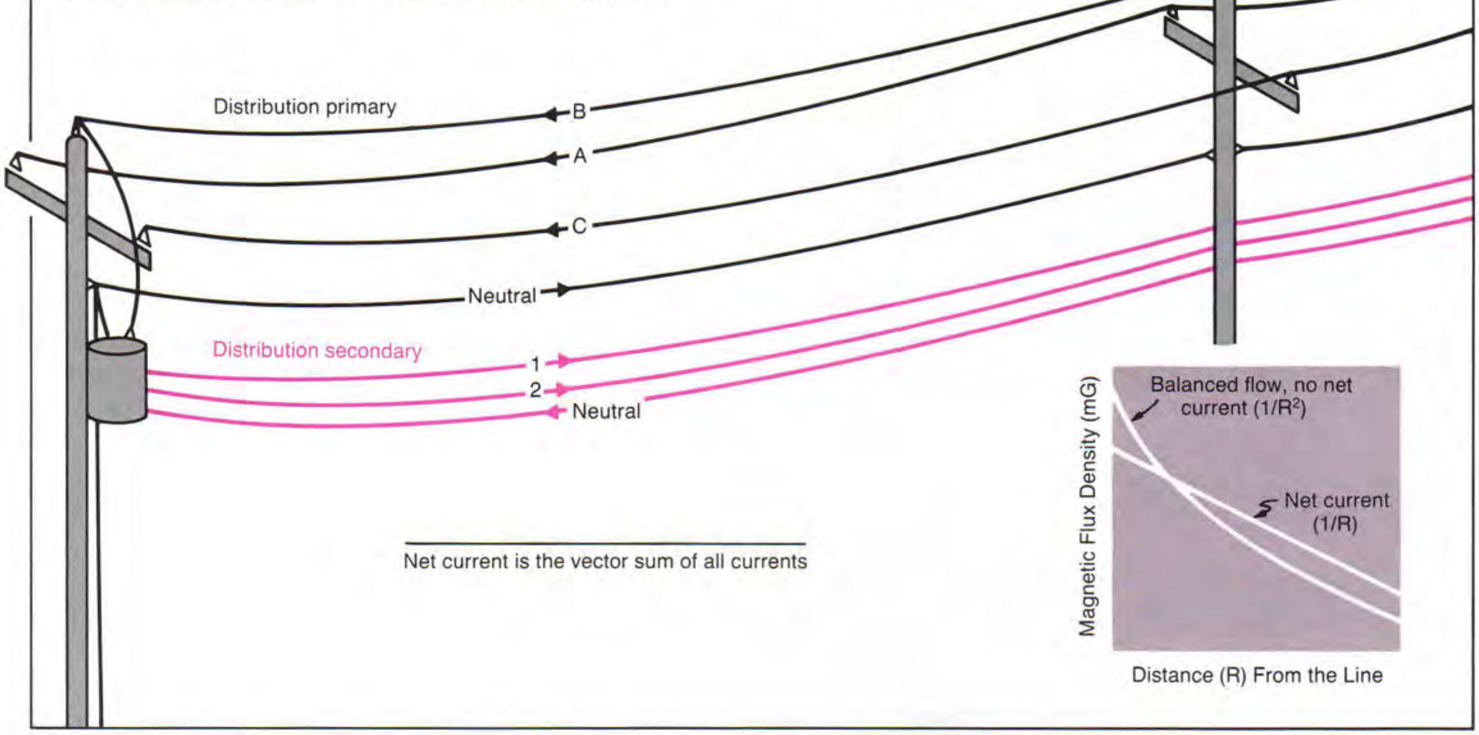
Meanwhile, most of EPRI's work to develop methods for modifying existing lines and for designing new lines with lower fields that also meet other environmental constraints will be centered at the HVTRC in Massachusetts. For both new and upgraded lines, each novel conductor arrangement may also require the development and verification of new support structures and insulator configurations. EPRI's Transmission Line Mechanical Research Center in Haslet, Texas, which is used for structural testing and analysis, could become involved in work on new and modified tower designs. Research managers believe the combined capabilities of TLWorkstation, the HVTRC, and the TLMRC, coupled with utility demonstrations, provide a likely path for the development of new designs and configurations.

Installing transmission lines underground is popularly perceived as a way of eliminating a circuit's magnetic field. While this can be the case in some specific circumstances, in others such an option could actually increase the magnetic field at ground level. The earth itself provides no magnetic shielding. But when a three-phase circuit is enclosed in an oil-filled, pipe-type cable—as is commonly used for underground transmission in dense urban areas—the effect of closely spacing the conductors largely cancels the magnetic field more than a few inches away, assuming there is balanced current flow among the phases. Current flow in transmission lines generally is balanced, compared with the flow in distribution circuits, although this is not always so.

Despite the use of underground transmission in major cities, most utilities are strongly averse to its mandated application for a number of reasons. The cost is double or even three to five times that of an overhead line, depending on location and circumstances. Such circuits are more difficult and costly to maintain and repair. And an underground line poses operational difficulties at lengths of more than 20–30 miles because of high capacitance that can choke its current-carrying capacity. The effect can be compensated for with shunt reactors but at

Distribution Fields: More Than the Sum of Parts

Magnetic fields from utility distribution systems are more complicated than those around high-voltage transmission lines, primarily because there are often two circuits—a higher-voltage primary and a lower-voltage secondary. Net current flow—the nonzero vector sum of all currents flowing on all the conductors—creates an additional magnetic field component beyond that from normal current flow on the lines. Net current results when return currents from customer loads disperse through ground connections and do not return on the neutral wires to the distribution transformers. The magnetic field from net currents falls off less rapidly with distance from the lines than the magnetic field from a set of three-phase conductors carrying no net current. Net current can sometimes be the dominant source of background magnetic field inside a house or building; other contributors can include nearby transmission lines, underground utility cables, building wiring and ground connections (such as water pipes), and appliances and electrical equipment.



additional cost and complication of the power system.

In any case, the expense of undergrounding would hardly be justified except where the lines are near people. Even there, relatively minor imbalances in current flow could materially increase the magnetic field near the line. And the line would be only a couple of feet underground rather than high overhead.

Already playing a support role in field management research for underground transmission lines is the EPRI Cable Test Facility at Waltz Mill, Pennsylvania. The laboratory has measured and determined the characteristics of fields from various types of underground cable systems under a variety of conditions. It has verified, for example, field levels of less than 15 mG a little over 4 feet away from a pipe-type, three-phase cable carrying 1650 amperes. Continuing work is expected to focus on improving techniques for predicting fields in the vicinity of underground lines. And recently begun EPRI research projects in construction techniques for underground transmission could lead to lower costs that might make that option more acceptable to utilities.

Rounding up return currents

While possible changes in the configuration of circuits represent a likely general approach to managing magnetic fields around high-voltage transmission lines, the picture is somewhat different for lower-voltage (4–35 kV) distribution lines. Here, the flow of current along typically single- or three-phase primary feeders and secondary circuits is rarely balanced because of the varying demand for electricity on the individual phase conductors that serve different customer sites. The resulting magnetic field intensities rise and fall with current flow.

But even if demand were steady and uniform across a distribution system, significant imbalances could remain because of stray neutral currents associated with secondary 120-V line-neutral connected loads. These dispersed currents do not always return on the distribution neutral wires as they are supposed to. Instead, they may take multiple return paths through many possible ground connections from the distribution system as well as at customer sites. The intensity of the magnetic fields from unbalanced currents on a distribution line falls off less rapidly than the field surrounding a set of conductors carrying balanced currents.

How an electrical service entrance at a building is grounded can also affect the flow of net current (the vector sum of all currents flowing on a set of conductors) that results from dispersed neutral currents and adds to the indoor magnetic fields from distribution systems. Secondary service drops at many homes and other buildings are grounded to metal water pipes to minimize fire and shock hazards. But the pipes can provide a conductive path for stray return currents from customer loads. They may even carry return current from neighboring service entrances that are similarly grounded.

Magnetic fields from dispersed neutral currents add to those from balanced distribution currents and, in some cases, can form the dominant source of low (but possibly significant) background indoor fields. Other potentially significant contributors to indoor fields can include various appliances from the kitchen to the workbench, nearby transmission lines, and unusual wiring configurations in the structure that create current loops.

"The dynamic interaction of magnetic fields from so many potential sources makes characterizing and understanding indoor fields a complex challenge, compared with the rather straightforward engineering calculations for determining the field generated solely by a transmission line," says Greg Rauch, a project manager in the Electrical Systems Division and coordinator for EPRI's magnetic field management activity.

Much of the insight into the dynamics of distribution lines, house wiring, and grounding systems comes from an ongoing nationwide EPRI survey of residential and nonresidential magnetic field sources. In a 1988 pilot study, the staff of the HVTRC developed special instrumentation and a survey protocol as well as some preliminary data on magnetic fields. One instrument being used is a stand-alone recorder coupled with a calibrated surveying wheel for studying the spatial variability of fields in different rooms and locations. Another tool is a waveform capture system developed for EPRI by Electric Research and Management of State College, Pennsylvania, for taking multiple simultaneous or time-interval magnetic field measurements. The nationwide survey is expected to eventually include 25 participating utilities in some 1000 randomly selected homes across the country. Less extensive surveys are also being conducted in a variety of other environments, such as offices, schools, workplaces, and electric power facilities.

Rauch says most measurements will be completed by the end of 1991. "One of the questions we expect the surveys to answer is what fraction of the population is exposed to fields, for example, from transmission lines, distribution lines, nearby substations, or the grounding systems in homes, and what the average levels of those different fields are. The results might suggest avenues for others to use in setting priorities, as well as measures, for reducing fields."

Grounding practices for low-voltage circuits (minimum requirements for which are specified in the National Electrical Code, issued by the National Fire Protection Association) are one focus of studies of options for reducing magnetic fields around distribution lines as well as in buildings. The less the flow of net current at service entrances, the less intense the magnetic field that is generated. Rauch says EPRI's pilot residential survey revealed that net current flow at a customer service drop usually manifests itself as measurable current (and magnetic field) on the building's water pipes if they are metal.

Water service workers know well that water pipes, typically used as a second ground connection because they offer a ready-made earth electrode, can be a common return path for stray neutral return current. The workers take special safety precautions to prevent shock hazard when removing or installing a water meter, for example. The American Water Works Association Research Foundation in Denver, Colorado, has approved funding for a project to investigate the effects of grounding electric service to water pipes.

According to Joel Catlin, a project manager for the drinking water industry's research group, the foundation's interests are threefold: whether currents on water pipes create a shock hazard to water utility workers; whether those currents promote or accelerate corrosion that may deteriorate the service line; and whether the currents increase the release of corrosion by-products (lead and copper compounds) above regulated levels in drinking water. Catlin says water utility managers have indicated that such a study of the possible effects of grounding electric service to water pipes is a high priority.

The American Water Works Association officially discourages the grounding practice, but the technique is nonetheless widely used in homes and buildings for safety's sake—to reduce the potential for fire or shock to residents under short-circuit conditions. In some areas, ground connections to metal water pipes are specified in local building codes. Magnetic fields can also result from neutral current on building structural steel (as in an office building) when that is used for a ground connection.

"Grounding practices may become a key issue in how to manage indoor magnetic fields," says Rauch. It may be that a much smaller number of better and more reliable ground connections could re-

A Laboratory House and More

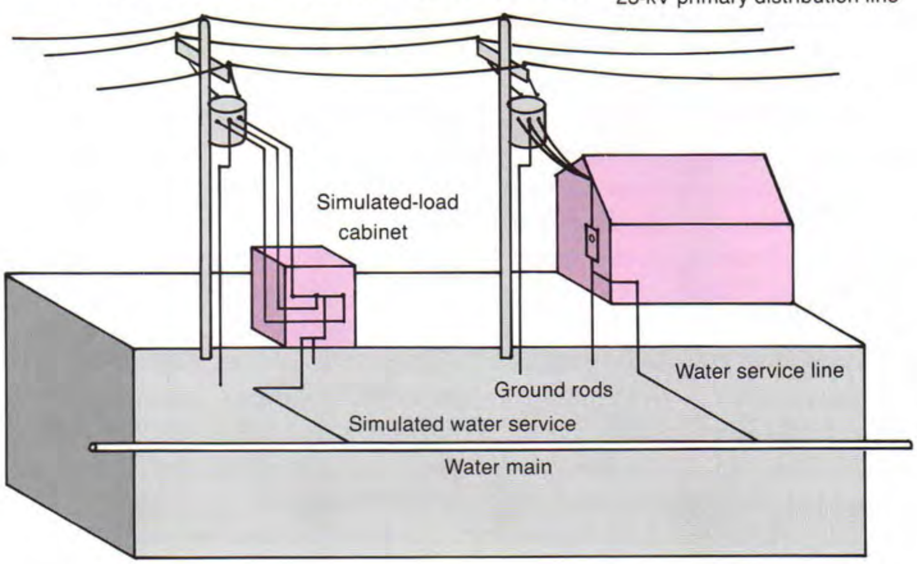
At EPRI's High Voltage Transmission Research Center near Lenox, Massachusetts, researchers are using an open-walled, instrumented laboratory house, complete with an overhead distribution line and simulated additional residential service drops, to analyze the complex dynamics of indoor magnetic fields. The setup, called the Magnetic Field Research Facility, includes a buried water main for ground connection with variable insertion resistance, nine transformers along a 1200-foot section of 23-kV primary distribution line, 17 simulated neighborhood loads, and different types of wiring, ground connections, and appliances inside the laboratory house. Special magnetic field recording instruments and analytical software are used for taking multiple field measurements as researchers create magnetic fields from the various sources under controlled conditions. Work at the facility has already detailed the role that grounding and net current flow at a house service entrance can play in the complex magnetic fields that are possible indoors.

Laboratory house and overhead distribution line

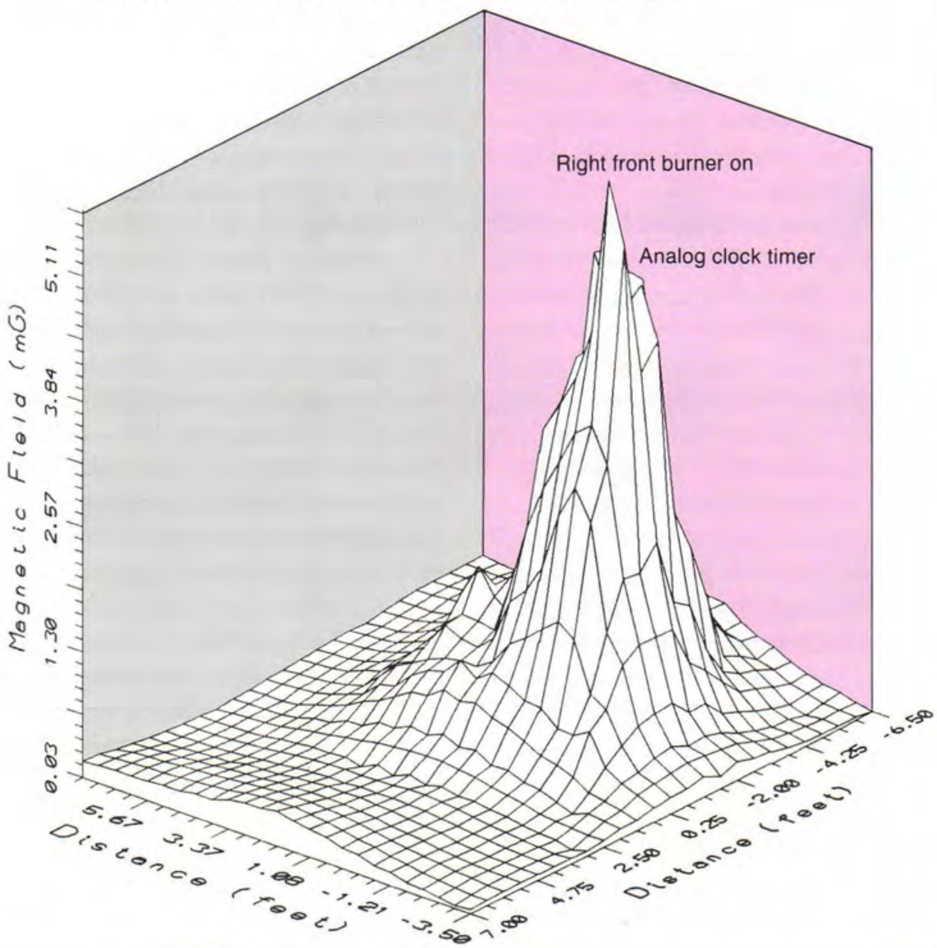
Stand-alone recorder and VANA wheel for surveys

Outdoor field measurement training

Typical arrangement of loads and grounding methods at EPRI's Magnetic Field Research Facility



Three-dimensional surface plot for an electric range



duce net current flows and associated magnetic fields. But before any changes in such practices are developed, Rauch adds, "the electrical engineering, contracting, and other appropriate affected professional communities have to carefully consider the implications for the safety of the present system. We're not suggesting compromising electrical safety by lifting a ground connection to a water pipe just to reduce the net current magnetic field. It makes no sense to increase a very real, known risk in order to reduce an uncertain, but possible, risk."

Rauch says there are possible alternatives to ground connections to water pipes that would eliminate net current flow at the service drop but provide adequate electrical safety in some other way. A grounding scheme favored in Japan, Germany, and some other European countries minimizes or eliminates ground connections at service entrances. Within buildings, major electrical loads are equipped with ground-fault interrupters—sensitive circuit breakers that trip open on sensing a small leakage current or short-circuit—to prevent shock and fire hazard.

This approach will be studied to determine whether it might have any applicability here. But research managers note there are significant differences between the distribution systems of other countries and the United States that could limit use of the approach, including higher service voltage (220 V versus 110 V) and higher-density housing.

With the completion earlier this year of an instrumented laboratory house at the HVTRC, EPRI is uniquely equipped to explore the interactive dynamics of indoor magnetic fields and new concepts for managing dispersed neutral return currents. The HVTRC's Magnetic Field Research Facility is a semifinished house equipped with instruments for taking many simultaneous measurements of magnetic fields and current flows. It is also much more.

The structure, outfitted with three different types of wiring, can be connected through one of six different service drops to a transformer and a 23-kV overhead distribution line. Several distribution grounding arrangements are possible. Other transformers and simulated loads, including up to 17 simulated neighboring residences, can also be line-connected.

The laboratory house wiring and the service drops simulating additional residences can be grounded to a buried water service line in which variable resistance can be inserted at various points. Current flows and magnetic fields can be recorded from these locations simultaneously as researchers vary the loads and return path impedances under controlled conditions.

"In effect, we have our own little residential subdivision here that we can control and reconfigure at will," says Gary Johnson, the HVTRC's manager of research program development. Johnson says work so far has confirmed the role that net distribution current and dispersed neutral return current play in complex indoor magnetic fields. Nearby transmission lines can also contribute to indoor fields.

Johnson says researchers hope to add to the complexity of the neighborhood's current flows and magnetic field environment late this year or early next by installing an underground distribution cable and evaluating its effects on field dynamics. Studies of distribution harmonic frequencies are also being conducted at the laboratory house and are part of the national residential survey protocol as well.

The HVTRC staff has developed special field measurement and recording equipment, as well as research software that can calculate and display magnetic field data as three-dimensional and contour maps. In addition to conducting regular seminars for utility personnel on how to take magnetic field measurements, the HVTRC last August provided a briefing and tour of the laboratory house for a group of state utility regulators.

In an effort focused on analytical tools for evaluating indoor magnetic fields, a software project in the Environment Division is developing a flexible, computer-assisted design–type program called RESICALC. When it is completed in a few years, users will be able to model indoor magnetic fields according to room dimensions, field sources, and intensities that they define. Ultimately, much of the data on indoor magnetic fields being gathered by EPRI and others will be incorporated in RESICALC, which is being designed to calculate and display three-dimensional maps of the fields within structures or rooms under various combinations of sources and current flows. The model may eventually be able to calculate and graph an individual's cumulative exposure to magnetic fields as the person moves through different rooms and field intensities.

Looking at other magnetic field sources

In addition to transmission lines, distribution systems, and indoor magnetic fields in general, two somewhat more special categories of field sources are being examined under EPRI field management activity. One—occupational exposure of certain utility workers—involves both the transmission and distribution areas but also other utility facilities. The second category involves various types of customer-owned end-use equipment, from commercial and industrial equipment down to home appliances that often contribute to the already complex fields indoors.

Worker safety has always been one of the highest operational priorities of utilities, and occupational magnetic field exposure is, in turn, becoming a priority as questions arise among researchers as well as among workers. Results of some epidemiologic studies have suggested increased risks of brain cancer, breast cancer, and leukemia among workers whose occupations involve higher-than-normal exposures to magnetic fields. Other studies have not found such indications.

EPRI's Environment Division is sponsoring epidemiologic and other research to determine the extent and risk of occupational exposure to EMF, especially among certain categories of utility personnel. The studies include a retrospective analysis of some 150,000 male employees of five major U.S. utilities that is being directed by David Savitz, an epidemiologist at the University of North Carolina. Extensive on-the-job measurements of EMF exposure among workers in various job classifications—including linemen and substation and power plant workers—are being taken to reconstruct and estimate occupational exposure histories.

EPRI research managers say that changes in work practices in areas around equipment generating high magnetic fields may be the best option for reducing utility personnel exposure. Certain areas in power system facilities—near large generators in power plants, for example, or around conductors and other components in substations—can have magnetic fields as high as several tens of gauss but do not normally require the frequent presence of workers. Time limits for workers with tasks in such areas might help reduce magnetic field exposures.

According to some utilities, live-line work on transmission lines is becoming less attractive to workers and others concerned about possible health risks from magnetic field exposure, in contrast to the well-managed shock hazard. EPRI managers say there is significant potential for increased application of robotic devices to allow personnel to work at greater distances from certain field sources. EPRI has already developed a robotic, remote manipulator arm for overhead transmission lines. Called TOMCAT, this device can effectively perform numerous key maintenance and repair tasks on a variety of lines of different voltages while its operators remain on the ground, away from the line. TOMCAT is expected to be commercially available by 1993. Work to develop prototype robotic devices for use in underground utility equipment vaults, which can have high magnetic fields because of often-substantial cable currents, is also under way.

Researchers suggest that one upshot of concern about magnetic field exposure among workers is likely to be an acceleration of the trend toward the use of more sensors and automatic surveillance equipment for monitoring or investigating conditions on overhead lines or even in substations and generating plants. Accurate, reliable, and low-cost sensors—some possibly based, for example, on fiber-optic technology—could significantly reduce the need for personnel to physically inspect or read data from some power system components.

At Ohio State University's Electrical Engineering Department, EPRI is sponsoring the development of detailed models for understanding how magnetic fields vary around the different current-carrying elements in transmission substations. Researchers are using a 1:67 working scale model of an actual 345-kV utility substation; the model is based on careful measurements of the fields at 300 various points in the substation. "Electrically, the model's current scale is 1:500, so 500 amperes on a conductor in the real substation is 1 ampere on the model," says Professor Stephen Sebo, one of the project's several researchers. "The voltage is low, probably 2–3 V, because what is important to model and measure is current flow." He says the scale model has working replicas of circuit breakers, switches, and wave traps in addition to conductors, but transformers are not included. "According to our measurements at real substations, there is hardly any magnetic field outside a transformer tank that is generated by the transformer itself."

As researchers measure the magnetic fields in the scale model under different current flow conditions, the data are being used by Professor Donald Kasten to build a computer model of the substation. This digital model, which could become available for utility use next year, is expected to be helpful in analyzing possible changes in equipment configuration or location to reduce magnetic fields. It will also be used later to assess the effectiveness of enclosing certain equipment within different types of possible shielding material.

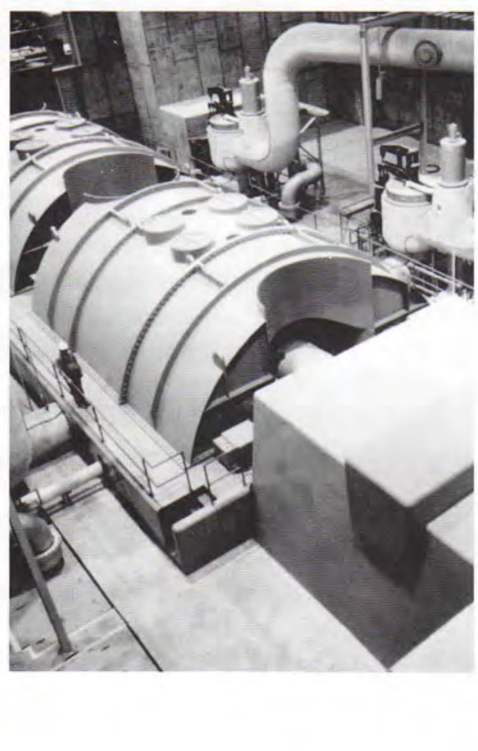
Ferromagnetic materials or perhaps other types of materials that deflect or alter magnetic fields may have some application as limited shielding for utility workers who spend significant periods of time exposed to high fields. EPRI plans a project to explore these possibilities and to evaluate candidate materials. There is a possibility that the new materials science field of conducting polymers (materials such as that used in the energy-absorbing Stealth aircraft technology) may offer some promise for magnetic shield material.

End-use equipment in the residential, commercial, and industrial sectors includes many diverse manufacturing enterprises. As concern grows about possible health risks of magnetic fields, most manufacturers are taking a cautious, wait-and-see approach to possible design changes to reduce fields in new equipment or products. (Two exceptions, as noted earlier, are computer monitors and electric blankets.)

For most equipment and appliance makers, liability implications and proprietary considerations would likely inhibit much advertising of design changes if and when they are made. "Our members are concerned about making too much out of magnetic field management at this point," says Douglas Bannerman, an environmental consultant to the National Electrical Manufacturers Association (NEMA). "If an electrical manufacturer came out with a new low-field design and touted that as a safer product, some

Concepts for Managing Occupational Exposure

Electric utility personnel who work on transmission or distribution lines, in underground equipment vaults, in power plants, or in substations are frequently exposed to strong magnetic fields around components that carry large amounts of current. Among EPRI's studies of magnetic field management is work that focuses on these utility occupational exposures. To minimize the time workers are in the presence of strong magnetic fields, changes in work practices and procedures may be designed. Specialized robotic devices, such as the EPRI-developed TOMCAT remote manipulator for live-line maintenance and repair, reduce worker exposures by increasing the distance between personnel and current-carrying equipment. As with robotics, more and better remote sensing equipment—possibly including fiber-optic-based technology—could reduce the need for personnel to physically inspect or approach lines or equipment carrying large amounts of current. EPRI-sponsored research is also exploring the potential for certain materials that might absorb or deflect magnetic fields to be used as shielding, most likely as temporary partitions or barriers around strong field sources where workers must spend significant periods of time. Such materials might include ferromagnetic materials or others based on recent breakthroughs in conducting polymers.



people would infer that the products marketed earlier were unsafe, and we have no technical data that would justify that sort of action or conclusion. We also have no knowledge that any design change to mitigate EMF would have any beneficial effect on possible health risks." But Bannerman says new designs would be carefully considered if science does clearly demonstrate a relationship between EMF exposure and health risks. NEMA members primarily manufacture industrial and commercial equipment; electronics and home appliances are the realms of other trade groups.

EPRI's Customer Systems Division plans to begin a three-year project in 1991 to identify the levels and ranges of electric and magnetic fields associated with a variety of end-use technologies. This effort will include thorough testing of end-use equipment in laboratory settings at EPRI's Power Electronics Applications Center in Knoxville, Tennessee, and at the HVTRC's laboratory house. According to William Smith, the manager of EPRI's Power Electronics and Controls Program, a primer on EMF around residential end-use equipment is expected to result from this work and could be available as early as next year. A similar report on the magnetic field environments in commercial and industrial settings is anticipated by late 1992.

EPRI is also seeking to establish working alliances and to coordinate activities with other groups, including the magnetic fields task force of the IEEE Power Engineering Society; the IEEE's Standards Coordinating Committee 28 (on nonionizing radiation); the international equivalent, CIGRE Study Committee 36 (on interference); and manufacturing trade groups, for example, NEMA and the Association of Home Appliance Manufacturers (AHAM).

Marian Stamos, AHAM's director of communications, acknowledges that home appliance makers are closely monitoring the EMF health effects issue and are looking to research groups such as EPRI and others for guidance and insight on possible risks and implications. "But basically we're on hold until it's clear whether there really is a problem. We know it is theoretically possible to change fields based on various wiring techniques and special design considerations that increase the distance between sources, such as the motor, and the user. But until there are reliable data that specify appropriate levels, it is difficult for manufacturers to redesign products. It's not a question of not being able to do anything. But unless science can say what is the relevant exposure level or dose rate to avoid, it's hard for a product designer to know what to do."

Focal point for research and information

EPRI's Hingorani notes the increasing attention and focus on magnetic fields in research programs at many levels—the federal and state governments, universities, private groups, and individual utilities as well as EPRI. Such diversity of effort, he says, "is bound to lead to some duplication, but it points up another role for EPRI to play. We would be quite willing to help coordinate the flow of information from all this research so that available resources can be used to the maximum effect. I don't mean to suggest that any group or agency should not sponsor work on field management. Individual states, of course, will do what they feel is necessary under the local circumstances and conditions.

"But to the extent that EPRI can serve as an information conduit, as a focus for what insight can be gained from all the research activity under way and as new information comes from the biomedical arena, I believe we can multiply the value of our work for utilities even more broadly to the EMF research and regulatory communities. It's very important that people who are in a position to make new rules for how our society will manage the uncertain risks from exposure to magnetic fields understand what that risk is and what is possible and feasible to do about it, so they can make decisions wisely," Hingorani adds.

EPRI research managers also stress the careful engineering analysis that must be a part of any strategy or specific options for reducing magnetic field exposure. "If magnetic fields are a problem, they are a very complex problem, and the engineering process that will be required to logically address field management without violating other essential criteria will itself be complex," says Frank Young, director of the Electrical Systems Division.

"Although we don't know yet whether EMF is a problem, it is nonetheless possible for engineers to begin to speculate about what can be done to reduce people's exposure to magnetic fields," adds Young. "So we're developing a list of options and enough information to establish relative rank and priority. For now, that is only prudent and perhaps all that prudence can support." ■

Further reading

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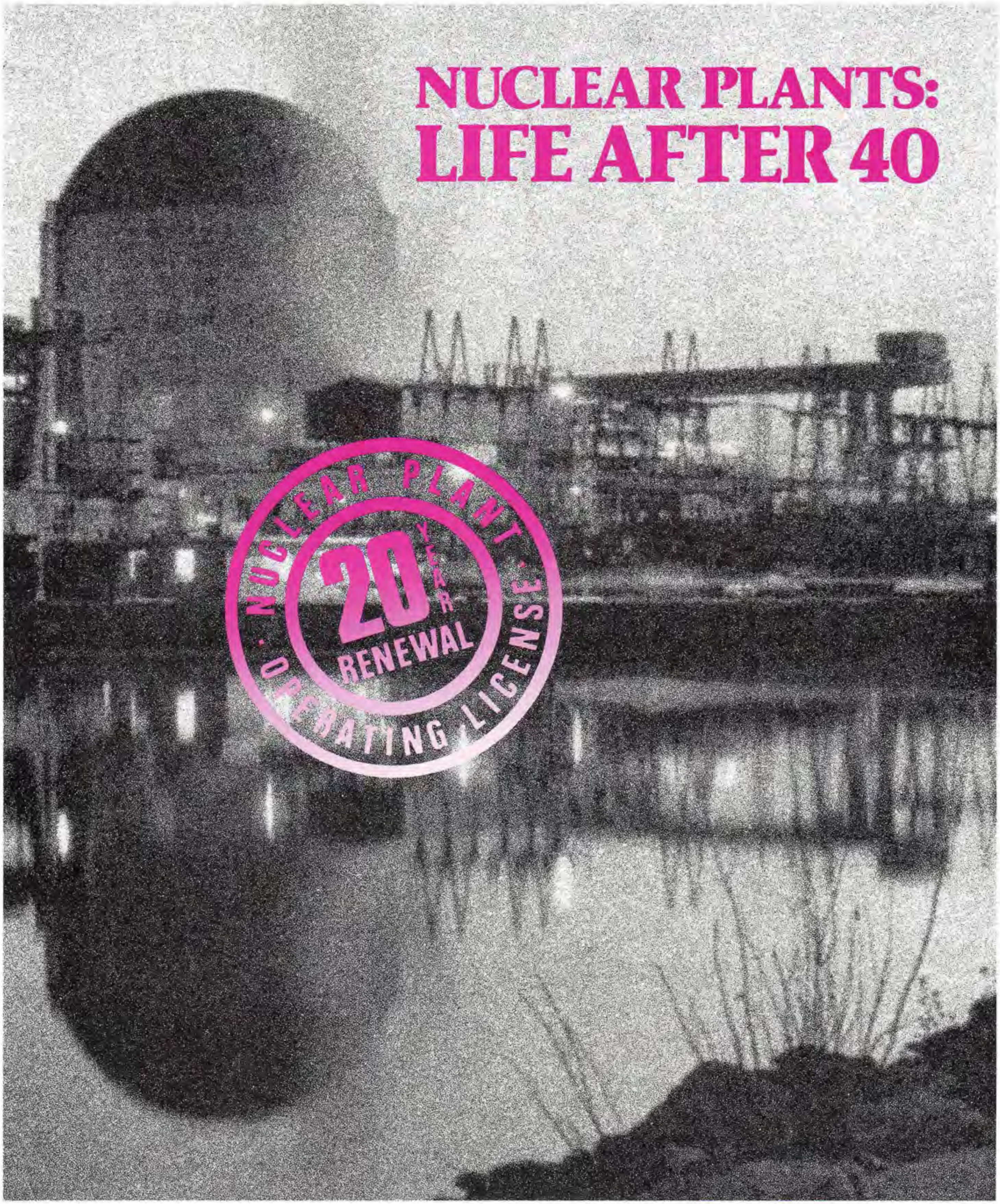
This article was written by Taylor Moore. Technical information was provided by Narain Hingorani, Richard Kennon, Greg Rauch, and Frank Young, Electrical Systems Division; Stan Sussman, Environment Division; and Marek Samotyj, Customer Systems Division.

NUCLEAR PLANTS: LIFE AFTER 40



As the population ages, so does the current fleet of nuclear power plants. But utilities believe that, as with people, there is still a lot of life in today's reactors after 40. Operating licenses for the oldest of the nation's 112 nuclear plants will expire beginning in the year 2000, but the utility industry and government authorities are laying the groundwork now to ensure that safe and reliable electricity generation can continue at these plants well beyond their original, 40-year terms.

Experts say the 40-year operating license term was defined somewhat arbitrarily in the 1954 Atomic Energy Act, which set the stage for the regulation and commercial use of nuclear power. Most federal licenses for hydroelectric plants were issued for 50-year terms, and 30 years was a commonly used utility amortization period for conventional fossil-fuel-fired generating plants. So lawmakers decided that nuclear plant licenses would run for 40 years but could also be renewed.

"The license term has very little to do with the actual service life of a reactor," says John Carey, an EPRI senior program manager. Carey notes that plants in many other countries with large nuclear power programs are issued open-ended licenses, with continued operation evaluated solely according to a plant's maintaining established levels of safety and economical performance.

But in this country, historical and regulatory circumstances have combined to make license renewal and plant life extension potentially a bigger issue than purely technical considerations might justify. Regulatory requirements for license renewal are now being spelled out by the Nuclear Regulatory Commission. In response to urging by utilities to define such requirements early so that cost estimates can inform strategic decisions about whether to seek an extended operating license, the NRC is in the midst of a multiyear rulemaking proceeding. It is expected to result in a final rule by the

THE STORY IN BRIEF

Operating licenses for the nation's earliest commercial nuclear plants will begin to expire in the year 2000. But the utility industry and government authorities are laying the groundwork now to continue safe and reliable electricity generation by some of these plants well beyond their original 40-year license terms. Regulatory requirements for license renewal are now being spelled out by the Nuclear Regulatory Commission, with a final rule for extending operation for an additional 20 years expected in 1991. EPRI and the Department of Energy are sponsoring two lead plant demonstrations of license renewal, as well as studies of generic issues posed by potential age-related degradation in major plant systems, structures, or components important to extended operation. The lead plant projects at Yankee Atomic Electric and Northern States Power are expected to serve as pathfinders for other utilities weighing the license renewal option.

middle of next year permitting license renewal for terms of up to 20 years. The utility industry is currently responding through the Nuclear Management and Resources Council (NUMARC) to a proposed version of the rule that was published this summer.

Meanwhile, EPRI (on behalf of the utility industry) and the Department of Energy (DOE) are actively involved in R&D to support the nuclear license renewal option. They are jointly sponsoring a series of studies to address generic technical issues posed by potential age-related degradation in major systems, structures, and components important to extended operation under a renewed license and to identify options for managing aging.

EPRI and DOE are also cosponsoring with two utilities lead plant demonstrations of the complete regulatory and technical program leading to a renewed operating license. These lead plant projects—at Yankee Atomic Electric's Yankee pressurized water reactor (PWR) and Northern States Power's Monticello boiling water reactor (BWR)—are expected to serve as pathfinders for other utilities weighing the license renewal option.

Earlier EPRI–DOE life extension pilot studies at utility plants confirmed the technical feasibility of extended operation. The studies also indicated that, compared with the cost of building new generating capacity—whether nuclear or fossil—the economic appeal of extending the service term of existing nuclear plants is, in most cases, compelling.

A strategic option for future capacity

The current crop of nuclear plants collectively represents some 100,000 megawatts, or about 15% of the installed generating capacity in the country. Last year, the plants supplied about 20% of all the electricity generated—but without emissions of air pollutants and the greenhouse gas carbon dioxide, which accompany fossil fuel combustion.

With occasional power shortages already occurring in parts of the East and many forecasts projecting a need for as much as 150,000–200,000 MW of additional generating capacity later in this decade, utility interest in preserving existing nuclear plants is not surprising. Industry officials have said the cost to replace current installed nuclear capacity would range from \$200 billion to \$300 billion.

The nuclear and utility industries, with government support, are designing and planning a new generation of advanced, standardized reactors that are expected to be available for utility order in the mid-1990s. Such reactors are designed for shorter construction times than have recently prevailed at nuclear units, and with projected costs that are competitive with new coal-fired capacity.

Nonetheless, the lead times and time-related costs involved in choosing and building replacement capacity later in this decade have created the current pressure for early definition of regulatory requirements for license renewal. Utilities are looking to the NRC to define the specific terms and conditions for license renewal, as well as to provide additional regulatory guidance, within the next year or so.

Several past chairmen of the NRC have noted the strategic importance of the agency's rulemaking for license renewal, and the current chairman, Kenneth Carr, has called it one of his highest priorities. DOE has also long recognized the key role that existing nuclear plants play in the electricity supply. Analysis of the generating capacity implications of license renewal figures prominently in the department's continuing efforts to draft a consensual national energy policy.

Eventual license renewal and extended plant operation are also priorities for utilities that operate nuclear plants, although at this point only a few beyond the lead plant utilities have established formal engineering programs for those goals. Because of the nature of the nuclear regulatory process, the industry is focused now on interacting through NUMARC with the NRC in its rulemaking. The rulemaking and related regulatory guidance will largely determine the overall scope and cost of the utility programs necessary to meet NRC requirements for extended operation under a renewed license.

Many utilities are reluctant to build any kind of new power plant because of the high cost and because of uncertainty over the willingness of state regulators to permit recovery of the full cost through rates. In view of the likely prospect of capacity shortages in some areas in the years ahead, "shutting down productive generating assets just because they reach the end of a 40-year license would only make the problem of ensuring an adequate supply of electricity that much worse," says Andrew Kadak, president and chief operating officer of Yankee Atomic Electric. The utility operates the Yankee plant at Rowe, Massachusetts, the country's oldest operating commercial reactor and the first that will apply for an extended license. "On a national scale, license renewal is not just an option, but a necessity," Kadak says.

Utilities are also aware, however, that opponents of nuclear power can be expected to oppose license renewal, both generally and in individual cases, on grounds that the plants are no longer economical or that they are less safe to operate because of their age. In some cases, intervenor groups (many of which fought plants' original operating licenses on similar grounds) can be expected to attempt to reopen overall safety and environmental issues in formal public hearings.

The NRC has already taken steps to limit the scope of regulatory review for license renewal to those issues relevant to continued operation of existing plants. "The proposed rule suggests that a license renewal decision will focus heavily on matters of significant age-related degradation in systems, structures, and components that are important to license renewal and that are not already being managed under existing utility mainte-

Systems, Structures, and Components: Focal Points in License Renewal

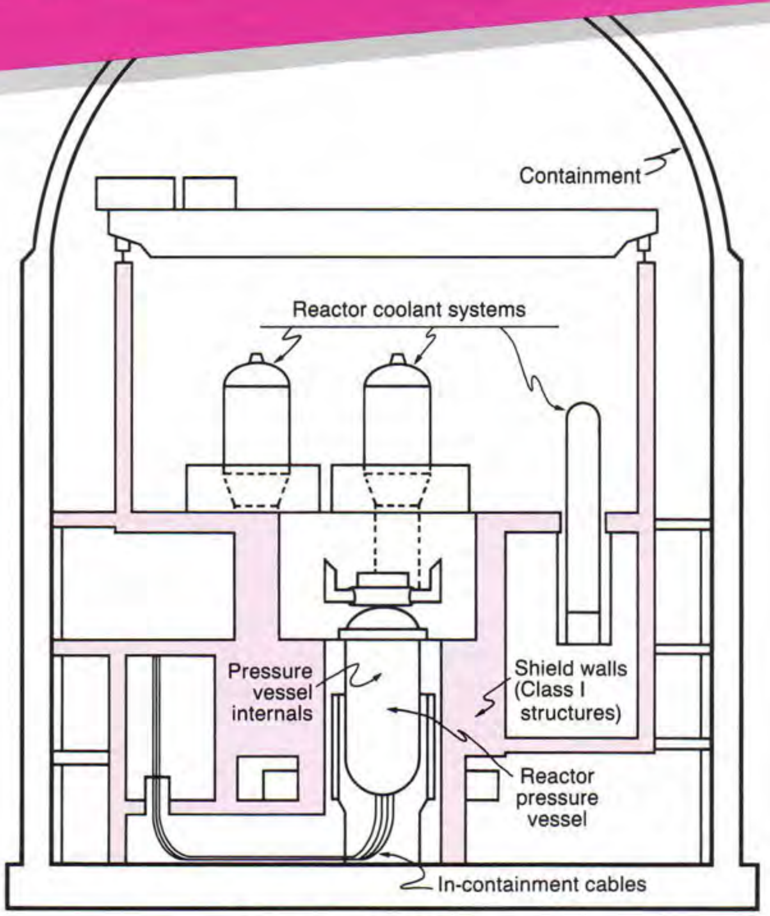
Utility and regulatory evaluation of a plant for license renewal revolves around those systems, structures, and components that are important to a plant's continued safe operation. These key focus areas are topically paralleled in a series of 10 generic Industry Reports developed by EPRI and the Energy Department's Sandia National Laboratories. The Industry Reports document the results of generic evaluations of the systems, structures, and components important to license renewal and comprehensively address the potential impacts of age-related degradation mechanisms, as well as the way those mechanisms are currently managed on an ongoing operating basis. Regulatory acceptance of the reports will provide utilities documentation that is referenceable in individual license renewal applications.

Industry Report Topics

PWRs
- Containments
- Reactor pressure vessel
- Pressure vessel internals
- Reactor coolant systems

BWRs
- Containments
- Reactor pressure vessel
- Pressure vessel internals
- Primary pressure boundary

Both PWRs and BWRs
- In-containment cables
- Class I (safety-related) structures



PWR, Dry Containment

nance programs," says Richard Burke, EPRI project manager for the Monticello and Yankee lead plant projects and a principal liaison with NUMARC on license renewal.

Two key principles of the proposed rule are that a plant's current licensing basis—those requirements in effect at the time of a renewal application—is sufficient to provide reasonable assurance of safety during the renewal period, and that the current licensing basis will be maintained through continued regulatory scrutiny as well as utility programs for managing age-related degradation.

The NRC is also pursuing a separate rulemaking proceeding to develop a generic environmental impact statement on license renewal that would limit requirements for environmental impact studies such as those required as part of all plants' original licensing.

"The industry's general position is that relicensing should not be a watershed event. It should be neither an opportunity to add new layers or dimensions of regulation nor an opportunity to reargue fundamental or ongoing plant operations and safety issues," adds Burke.

Burke's point reflects a consensus among EPRI's specialists in nuclear plant life extension, based on studies dating back to 1978, that there are no unique technological challenges posed by extended plant operation. Virtually all age-related degradation that might be of concern is already being addressed on an ongoing basis. "There's nothing magic about license renewal," says Carey. "It's not as though something different happens at the end of the license term. There just has to be more of the same sound engineering, operation, and maintenance practice that a plant should already be doing. The only things new are that the maintenance planning horizon is longer and it takes on more strategic priority.

"Maintenance planning, which is already done on a day-to-day basis to minimize outage time and replacement power costs, simply has to become more long-term in view, more strategic," says Carey. "For life extension, you need to be always looking many years out—maybe 20 to 30 years—in considering the most economical approach to replacing or refurbishing components or upgrading sytems."

According to Gerald Neils, executive engineer at Northern States Power and a senior industry expert on life extension, "The major critical components at our plants—for example, the reactor pressure vessels and the containment buildings—have useful life estimates well in excess of 60 years, and most other components are subject to a continuous program of maintenance, refurbishment, and replacement."

Melvin Lapides, a technical specialist in EPRI's Nuclear Power Division who managed most of the early work that confirmed the feasibility of extended plant operation, says it is important to distinguish clearly between what is unique to license renewal—a regulatory matter—and what is really straightforward engineering for extended service. "The bulk of the work that is involved in extending plant and equipment service is conducted routinely," says Lapides. "Life extension really means a process for determining how useful it is to continue operating a plant or some component over an extended time. The key question is not so much, can you replace major components? The answer to that is yes. Instead the question is, can you do it in an organized, planned fashion so that the cost is acceptable?

"Most of the technical work involves understanding material properties and the mechanisms of how things wear out," Lapides continues. "While there are challenges in the technology of component life estimation, materials and performance monitoring, and the like, utility engineers are interested in these areas independent of the license term. The fact that current licenses will someday expire and the NRC has to create new rules for renewing them is really an artifact of law."

Utilities taking the initiative

While the current focus in license renewal is on the NRC rulemaking, Carey points out, "there has been a lot of work by the utility industry over the last 12 years that has brought us to this point. EPRI, DOE, and a few utilities realized some time ago that we needed to get the wheels in motion for license renewal and extended service or we would arrive at some point in the next 5 to 10 years and not be able to renew licenses." So began a series of EPRI technical studies that both analyzed the feasibility of life extension and communicated results and methods of economic analysis to utilities.

Carey adds that as a result, in contrast to the usually reactive nature of nuclear power regulation, "utilities have in this case been pressing the NRC to establish license renewal rules. It's been a very proactive and interactive development." Through NUMARC, utilities have provided extensive input and feedback to the NRC at several stages in the rulemaking process.

"The nuclear utility industry has taken the lead in developing the technical and safety basis for license renewal," says Edward Griffing, a NUMARC technical manager closely involved in the industry's response to the current rulemaking. "As a result, we've had a very productive relationship with the NRC."

EPRI studies in the late 1970s indicated the technical feasibility of extended plant operation. Since then, EPRI and DOE have conducted a coordinated research program, including work to address age-related degradation mechanisms, to develop guidelines and industry technical reports, and to systematically evaluate the requirements for life extension in two pilot studies at utility plants in advance of and in support of the lead plant demonstrations.

The pilot studies, begun in 1985 at Virginia Power's Surry-1 PWR and NSP's Monticello BWR, evaluated in detail both the economic feasibility of life extension and the potentially critical plant equipment that could influence a utility decision. Both studies, which included in-plant inspection and testing, concluded that there were no major technical obstacles to either unit's operating considerably longer than its nominal license term.

Both pilot studies identified a strategy of proactive, preventive maintenance, coupled with enhanced inspection and testing for managing age-related degradation in systems and materials, as key elements of effective life extension programs. Implicit in such enhanced maintenance and monitoring activity is the accumulation and use of more-extensive maintenance, inspection, and test records to spot trends or changes in material properties or performance.

The Monticello pilot study suggested that for BWRs the most generically important deterioration mechanisms are the various corrosion-related phenomena within the primary pressure boundary. Such corrosion—including intergranular stress corrosion cracking in coolant piping—has occurred at most reactors of that type and is already managed on a continuing basis through existing maintenance and water chemistry programs.

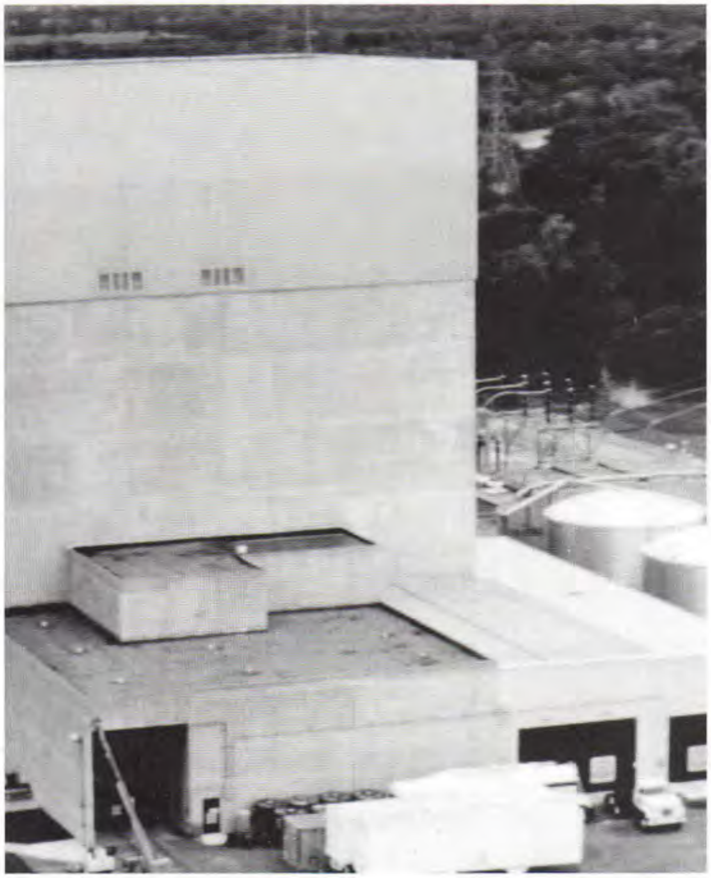
The Monticello study identified a benefit-cost ratio for life extension of about 4:1. It even suggested that the short-term benefits of life extension–oriented maintenance—including improved availability and outage planning and less corrective maintenance—might pay for such a program quite apart from the benefits of operation beyond the original license term.

The Surry study was cosponsored by the Westinghouse Owners Group and the French national utility, Electricité de France, in addition to EPRI and DOE. It identified thermal and neutron embrittlement and fatigue as the primary degradation mechanisms for such key components as the reactor pressure vessel and support structures, the pressurizer, and the primary coolant piping. An economic assessment methodology developed by the utility found that the bulk of the

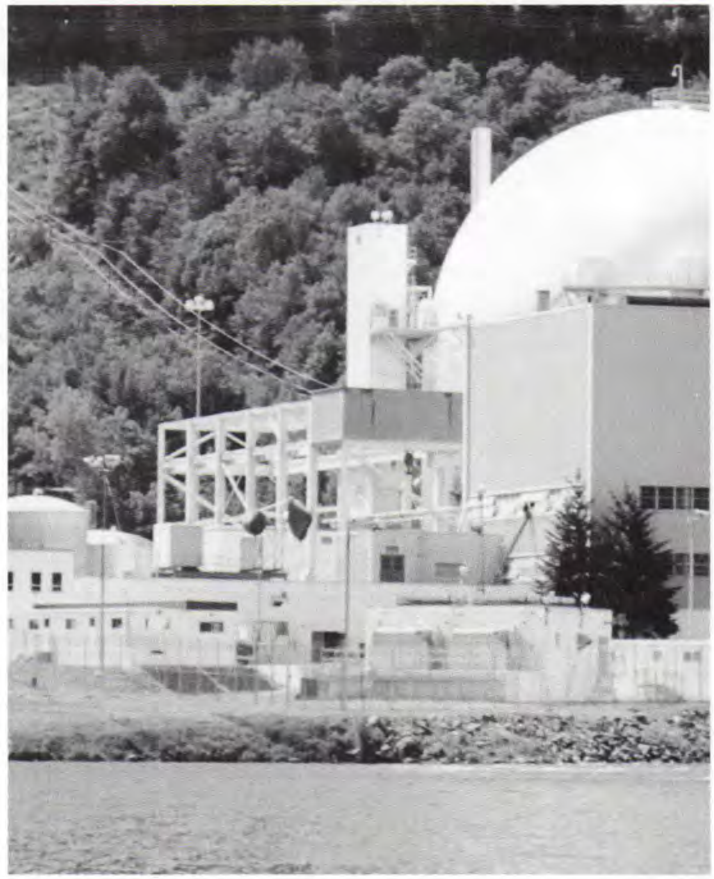
Lead Plants: Blazing the Trail for License Renewal

In a cooperative industry initiative, EPRI and the U.S. Department of Energy are cosponsoring lead utility plant demonstrations of the license renewal process at two plants whose original licenses are among those nearing expiration. The lead plants—one a PWR and the other a BWR—will serve as pathfinders for other utilities to follow through the complete regulatory and technical program leading to license renewal. The PWR is Yankee Atomic Electric's 175-MW Yankee plant in western Massachusetts. The BWR is Northern States Power's 536-MW Monticello plant near Minneapolis.

Monticello



Yankee



benefits of extending operation at Surry-1 would stem mainly from lower fuel costs and the postponement of the capital cost of replacement coal-fired capacity.

With the exception of the reactor pressure vessel, the containment building, and other major concrete structures, virtually every nuclear plant component has been replaced at one plant or another at least once, providing a base of experience and data for extended-operation maintenance planning. Early EPRI life extension studies concluded that even pressure vessel replacement was technically feasible, but it might cost 10–15% of what a new plant would cost, according to Lapides.

Neutron embrittlement of the reactor vessel is of current regulatory interest at some operating plants, and the subject is already the focus of industry R&D efforts (through EPRI) and NRC requirements. High levels of copper and nickel impurities in the steel used for some reactor vessel components can make the steel more sensitive to high, long-term neutron bombardment. Age-related degradation mechanisms, including neutron embrittlement, for both BWR and PWR vessels are also being comprehensively addressed in two of a series of industry topical reports to the NRC as part of its license renewal rulemaking.

A potential solution to extreme radiation embrittlement is to restore the ductility of the steel through a heat treatment process called thermal annealing. There is increasing R&D interest in the technique. EPRI research managers recently visited the Soviet Union to learn about Soviet experience in limited annealing of reactor vessels. Special heaters have been used at nine Soviet PWRs to raise the temperature of the metal along the vessel beltline welds to 454°C/850°F for about six days, restoring ductility and toughness that had diminished under high neutron exposure.

"Pressure vessel embrittlement is an ongoing issue and, certainly as plants get older, it becomes more important as you increase the vessel steel's neutron exposure," says Carey. "But there is no specific mention of it in the proposed license renewal rule because it's already covered under an existing NRC rule, the applicable pressure vessel code requirements, and the current utility compliance programs."

Anything that is new in considering age-related degradation of pressure vessel integrity is being comprehensively addressed in 2 of the 10 generic industry technical reports that EPRI and DOE (through Sandia National Laboratories) are preparing for submission to the NRC. EPRI and DOE/Sandia each are developing 5 reports documenting the results of generic system, structural, and component evaluations to directly support regulatory review of license renewal applications. The individual topics span containments, reactor pressure vessels, reactor vessel internals, and coolant systems or primary pressure boundary, as well as incontainment cables and Class 1 structures—including, for example, control rooms and cooling-water intake structures.

"The reports are the principal vehicle for providing technical support to the industry for license renewal," says Jeff Byron, an EPRI project manager for some of the reports. (EPRI's Richard Burke, who serves as NUMARC's industry reports manager, coordinates all work on the topical reports.) Byron says EPRI has provided substantial input to the work on all

The Top 20 in License Expirations

The Yankee plant, with its original 40-year operating license set to expire in the year 2000 if not renewed, tops the list of license renewal candidates and is also the lead utility plant to demonstrate the process for other PWRs. Ninth on the list (ordered by year of original license expiration) is Monticello, the lead utility project plant for BWRs, which is getting an early start on its renewal application.

Plant	Type	MW Rating	Utility	State	Expiration
Yankee	PWR	175	Yankee Atomic Electric	Massachusetts	2000
Big Rock Point	BWR	72	Consumers Power	Michigan	2002
San Onofre-1	PWR	436	Southern California Edison	California	2007
Haddam Neck	PWR	582	Northeast Utilities	Connecticut	2007
Nine Mile Point-1	BWR	620	Niagara Mohawk Power	New York	2008
Oyster Creek-1	BWR	650	GPU Nuclear	New Jersey	2009
Ginna	PWR	470	Rochester Gas & Electric	New York	2009
Dresden-2	BWR	794	Commonwealth Edison	Illinois	2009
Monticello-1	BWR	536	Northern States Power	Minnesota	2010
Robinson-2	PWR	700	Carolina Power & Light	South Carolina	2010
Millstone-1	BWR	660	Northeast Utilities	Connecticut	2010
Point Beach-1	PWR	497	Wisconsin Electric Power	Wisconsin	2010
Dresden-3	BWR	794	Commonwealth Edison	Illinois	2011
Surry-1	PWR	788	Virginia Power	Virginia	2012
Point Beach-2	PWR	497	Wisconsin Electric Power	Wisconsin	2012
Turkey Point-3	PWR	693	Florida Power & Light	Florida	2012
Pilgrim-1	BWR	655	Boston Edison	Massachusetts	2012
Palisades	PWR	805	Consumers Power	Michigan	2012
Quad Cities-2	BWR	789	Commonwealth Edison	Illinois	2012
Quad Cities-1	BWR	789	Commonwealth Edison	Illinois	2012

10 reports, now completed and submitted for regulatory review. By issuing a Safety Evaluation Report on each of the industry-submitted reports, the NRC makes them generically referenceable by utilities in individual license renewal cases.

Each of the reports evaluates all plausible age-related degradation mechanisms that may occur and identifies any that are potentially significant and that are not already being addressed under existing regulatory requirements and utility maintenance programs. The studies then outline a range of options that are applicable for dealing with those mechanisms, including such steps as increased inspection, on-line monitoring, sampling and nondestructive evaluation, and cycle counting for fatigue analysis.

According to NUMARC's Griffing, "The industry reports series is one of the most significant things EPRI and DOE are contributing to the current license renewal process. These reports will relieve the 54 utilities with currently licensed plants of a significant burden: when each files its application for renewal, it can refer to these reports, knowing that the NRC has agreed by way of the Safety Evaluation Report that the generic reports cover the issues on the major components. Each plant will have to verify that it is within the envelope conditions, however, and have data to back that up."

EPRI and DOE/Sandia have also contributed to the development of a screening methodology being refined at NUMARC for submission to the NRC. The proposed license renewal rule calls for a systematic assessment by utilities to determine which systems, structures, and components are important to renewal. The screening methodology, intended as guidance on how to perform such an assessment, is getting its initial workouts in the lead plant demonstrations.

Leading the way to license renewal

At Rowe, Massachusetts, the country's longest-operating nuclear plant—and one of the current fleet's best-performing units—is gearing up for another run at the record books. The founders of Yankee Atomic Electric pioneered commercial nuclear power in 1954 when they decided to build Yankee, "so it's only logical for us to also lead in taking the next step and go for an extended license," says Kadak. Owners of the 175-MW PWR, which started up in 1960—only four years after the decision to build it—expect to file for license renewal next June.

Yankee has consistently been a standout performer. Kadak says the plant's capacity factor has exceeded the industry average in all but 2 of the last 15 years and has beat its own lifetime average for each of the last 5 years. It is one of only five plants in the nation recognized this year by the NRC staff for sustained good performance.

"To say that nuclear plants become less reliable with age simply isn't true—at least for Yankee," adds Kadak. "The reason for this stable performance is the vigorous monitoring and maintenance programs we've applied." Kadak says a typical coal-fired plant of comparable age would not have maintained such performance over the long haul because fossil fuel plants are not subject to the stringent regulatory requirements of nuclear plants or the same comprehensive monitoring and maintenance.

In some respects, Yankee is different from plants of more recent vintage: the four-loop Westinghouse PWR (an almost direct transfer of an early submarine reactor design) is contained, along with the primary cooling circuit, within a large, elevated steel sphere, in contrast to the modern steel-lined, reinforced-concrete containment buildings at most other plants. But Kadak says the differences with larger, more recent plants matter little in terms of license renewal. "Everybody has pumps and valves, and each component has to be evaluated for its ability to perform safely and reliably."

Kadak says numerous changes and upgrades have been made at Yankee over the years, either to improve performance or to maintain conformance with current safety standards and regulatory requirements. Two major examples are the turbine, which has been replaced, and the control room, which has been upgraded with computer systems. "We installed the first operational safety parameter display system," adds Kadak. "If you look at old photographs of the control room, you'll see that you could almost dance in there then. Today, the control room is filled with up-to-date electronics and control and monitoring instrumentation that have been added to meet changing regulatory requirements."

Preliminary cost-benefit studies for license renewal and extended operation have been conducted at Yankee; Kadak and EPRI managers say the results are definitely favorable. "We estimate the capital cost of running for a 20-year renewal term at $150/kW," says Kadak. That puts the cost of license renewal for Yankee at around one-tenth the cost of new coal-fired baseload capacity and makes continued nuclear generation at Yankee "competitive with gas over the long haul, depending on assumptions on gas prices," he adds. "We feel very comfortable proceeding on those kinds of numbers." EPRI's Carey says license renewal economics should look even more favorable for larger plants with more capacity over which to spread fixed costs.

For over two years, the Yankee staff has been closely analyzing the plant's fitness for extended service and preparing its overall life extension plan as the regulatory requirements have evolved and become clearer. Staff have even been using computer-based expert systems technology in evaluating aging mechanisms in light of operating experience. Assuming a June 1991 submission for license renewal, two years of NRC review, and possibly another one to two years for public hearings, "conceivably we could have a renewed license for another 20 years by 1995," says Kadak. Yankee's original license term would expire in 2000.

Kadak says the lessons about license renewal that he draws from Yankee's experience are sound advice for any nuclear utility: "Prudent operations and maintenance spending really pays off in the long run. Maintenance should be seen not as a burden but as an opportunity to continue to get reliable electricity from a plant beyond the license term. Every good maintenance job, then, is an investment in the long-term life of the facility."

Northern States Power also is known for its proactive stance toward nuclear plant maintenance, and it has excellent plant performance records that have been consistently recognized by the NRC and the Institute of Nuclear Power Operations. The lead plant demonstration of license renewal at its 536-MW Monticello BWR is part of NSP's three-reactor life extension program, which includes its two 500-MW Prairie Island PWRs. Monticello's current license will expire in 2010, and those of the Prairie Island reactors will run out in 2013 and 2014. Together, the three reactors represent approximately 30% of NSP's current installed generating capacity.

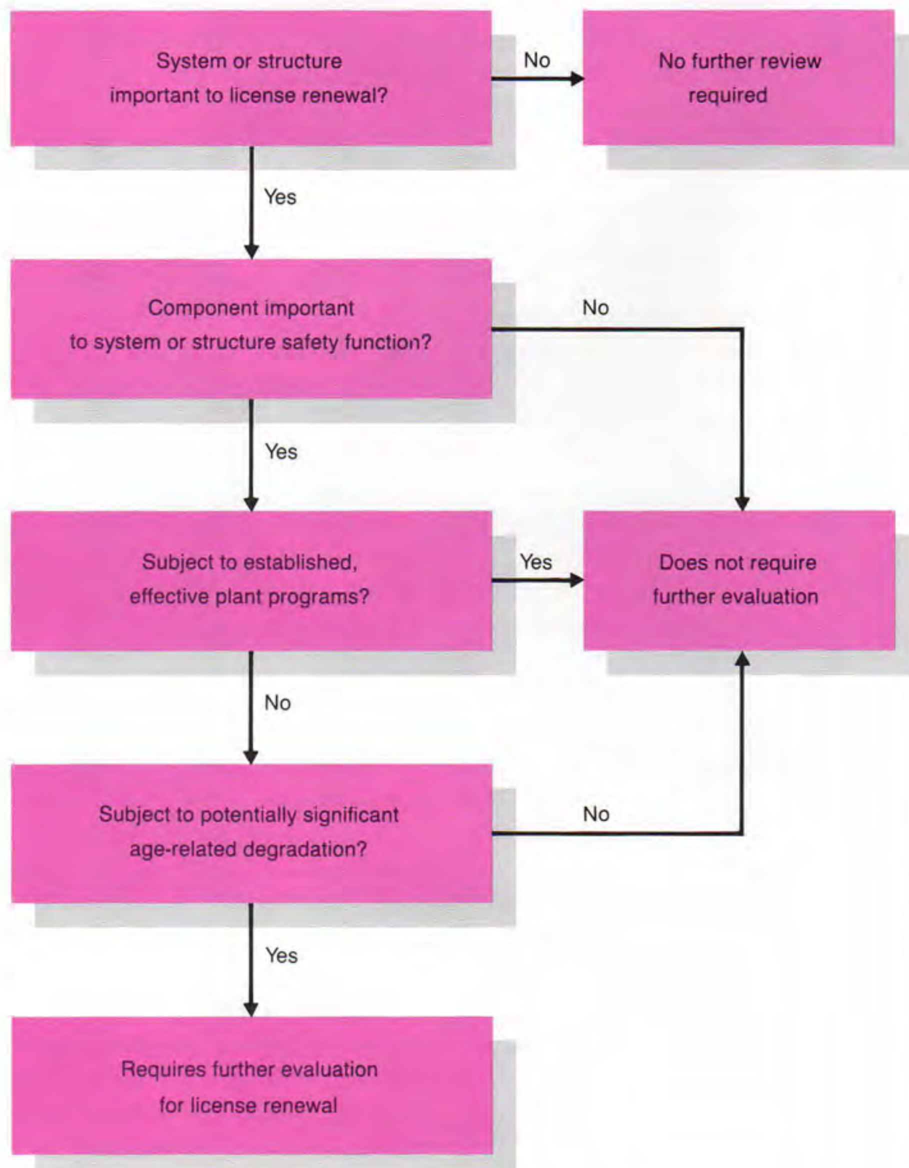
NSP's program began in 1985 with the EPRI- and DOE-sponsored pilot feasibility study at Monticello. With its own funding, the utility began a similar planning program for Prairie Island in 1987. NSP is providing some two-thirds of the funding for the Monticello lead plant demonstration. Submission of the application for license renewal is planned for late 1991, with NRC approval anticipated as early as 1993.

Detailed technical reviews for most major systems, structures, and components have been conducted for both the Monticello and Prairie Island plants. And environmental monitoring programs are in place at both plants to gather data on in-plant operating conditions to support analyses of extended component service life.

NSP says several formal tests and inspections have been performed on piping, metal structures, concrete, cables,

Evaluation Process for License Renewal

Utilities and the Nuclear Regulatory Commission will both follow the same general approach to evaluating nuclear plants for extended operation, as outlined in utility plant screening methodologies and in recently issued NRC rules for license renewal. The process first focuses on identifying all plant systems and structures that are important to license renewal. Components of those systems and structures are then evaluated in terms of whether they are important to safety functions, whether they are covered under established, effective plant programs, and, if not, whether they are subject to potentially significant age-related degradation. If they are subject to such degradation, they are further evaluated as to whether additional aging management is required for license renewal.



and other components to detect corrosion, thinning, cracking, and other forms of aging. Where such deterioration has been found, corrective or mitigating measures have been taken.

"Monticello's test and inspection results indicate that the plant's components and structures are generally in good condition, with some areas experiencing potential degradation that might result in the need for long-term component replacement," says NSP's Neils. "Significant findings include moderate corrosion of the drywell shell at its concrete interface, erosion-corrosion of the moisture separator cross-under piping, condenser wall thinning, erosion of feedwater heater surfaces, and corrosion of the vent line interiors. We have repaired these areas and continue to inspect and test to support extended life." Many of these aging mechanisms have also been reported at other nuclear plants.

To document analyses of trends in component life for eventual NRC review, NSP plant engineers have developed life extension workbooks that compile all critical data and permit a continuous determination of service life. Monticello has also conducted a detailed review of its maintenance program to identify improvements that will help extend component life. Over half of more than 150 recommendations have been instituted so far. These include periodic equipment disassembly and cleaning, lubrication, and other preventive maintenance. Records preservation programs have been implemented at Monticello and Prairie Island to gather and store critical operating data, maintenance results, and inspection reports for future use.

Formal cost-benefit analyses have identified substantial economic benefits of extended life at Monticello as well as Prairie Island. Both plants indicate net present value benefits of extended operation of over $300 million. NSP also assessed the immediate gains in availability and improved maintenance that are achieved through life extension activities and calculated that the value of those alone exceeds the total projected costs of life extension and license renewal. NSP's cost-benefit analysis puts the overall cost for extending operation at Monticello at about $200/kW.

Life extension personnel at Monticello are presently conducting additional component technical evaluations. These were identified last year through the use of a preliminary industry-developed plant-screening methodology that indicated the key systems and equipment that will likely be subject to NRC review during the license renewal process. Such evaluations are expected to continue through the middle of next year.

An ongoing need for R&D

In addition to the plant-specific pilot and lead plant projects, EPRI and DOE have also sponsored generic variant studies on the other PWR designs (by Babcock & Wilcox and Combustion Engineering) to complement the current work involving Westinghouse PWR and General Electric BWR designs. A number of other EPRI and DOE projects are also providing technical support for license renewal and life extension. These include studies of new methods to better address age-related degradation mechanisms and their effects, as well as tools for economic evaluation and life-cycle management to optimize plant performance over an extended period. The NRC independently conducts its own plant and component aging research program that parallels much of the industry-sponsored activity.

As the nation's current fleet of nuclear plants gets older and more of them reach a critical decision point about whether to seek license renewal, utilities will benefit substantially from the spadework that EPRI, DOE, and the lead plant utilities are now pursuing. Improved understanding and effective management of age-related degradation will ultimately translate to a more strategic focus on preventive maintenance as the way to prevent and correct what everyone who owns an automobile knows is an inevitable process of wear. But as Yankee Atomic's Kadak notes, "Utilities aren't going to treat such valuable, productive assets as generating plants like cars to simply replace when they wear out."

The expiration of current licenses for most plants is still some years away. But EPRI's Carey emphasizes that the lead time necessary to plan replacement capacity and the time required to prepare a license renewal submission, as well as the period of actual regulatory review, make it "later now than many utilities may think. Relicensing will most likely prove to be less costly for a utility that is not trying to get a license renewed in a crisis mode. But to avoid that, utilities must begin preparations early. Those utilities that have already begun assessing their plants for extended operation are deriving immediate economic benefit from the improvements identified and made in preparing for license renewal." ■

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This article was written by Taylor Moore. Background information was provided by Richard Burke, Jeff Byron, John Carey, and Melvin Lapides, Nuclear Power Division.

Solutions for Solid-Particle Erosion

Engineers who have inspected utility turbines in the United States bring back stories of serious damage—severely eroded turbine blades, valve stems with holes eaten through them, nozzles almost entirely worn away. The problem is called solid-particle erosion (SPE). And since the phenomenon was first detected in this country some 30 years ago, it has cost utilities billions of dollars in operation and maintenance costs for the steam turbines in high-pressure, high-temperature fossil fuel systems.

Today SPE damage remains one of the most significant performance problems among U.S. utilities, affecting roughly 80% of fossil fuel systems to some degree. According to the most recent industry estimate, SPE alone is now costing the utilities at least $150 million annually in reduced efficiency, lost power generation, and maintenance of damaged turbine components.

SPE is caused in part by a form of iron oxide called magnetite, which forms a scale-like surface inside the tubes of utility boilers. The magnetite is created by a chemical reaction between the surface of the steel tubes and the steam flowing through them. Typically, after about five years of growth, the magnetite becomes susceptible to cracking and flaking, particularly when a unit is heated during startup, as the base metal expands at a different rate than the scale. Jostled loose by the steam rushing past, the magnetite flakes become entrained in the steam flow. Ultimately they enter the turbine, where, like pellet spray from a shotgun, they pepper everything in their path.

As the particles strike various turbine components, they break up into smaller pieces, about the size of a grain of sand. Experts, in fact, often liken their effect to that of sandblasting. Erosion usually occurs in the first stages of the high-, intermediate-, and low-pressure sections of a turbine. These stages are the first to come into contact with the steam as it enters each section in a narrow, high-velocity

THE STORY IN BRIEF

Damage to turbine blades from solid-particle erosion is costing utilities at least $150 million a year in reduced efficiency, lost power generation, and maintenance of damaged components. More than a decade of industry research to characterize and quantify the problem has brought both consensus on the mechanisms of SPE and development of a variety of options for controlling it. While a number of solutions have been investigated for retrofit application, experiments have shown that a combination approach currently offers the most effective result at reasonable cost—routine chemical cleaning of boiler tubes, where the erosive particles form, and the application to turbine blades of protective coatings, several versions of which are now commercially available. For the future, newly developed turbine designs with modified steam path geometries are likely to significantly reduce the severity of SPE.

channel. But magnetite particles alone are not responsible for SPE. As experts in the field have discovered over the years, the geometry of the path that the steam follows through the turbine is also a big factor. Field studies have shown that modifications in the design of turbine components can greatly reduce the frequency and severity of the particle impact.

The degree of SPE varies greatly from unit to unit. In some cases, utilities report, SPE has actually caused forced outages. More commonly, though, the erosion leads to a gradual decline in efficiency. Utilities have typically been forced to abandon their five-year maintenance cycles and open up their turbines for overhauls every two to two-and-a-half years. Opening a turbine can alone cost a couple of million dollars in labor and outage time.

SPE hasn't always plagued the utility industry. Ironically, the problem was exacerbated by the more efficient, high-pressure, high-temperature units introduced in the late 1950s. By the 1970s it was clear there was a need for industrywide action. In response, EPRI and the Steam Power Panel of the American Society of Mechanical Engineers (ASME)—who were involved in separate SPE efforts—joined forces to organize a workshop on SPE. Held in 1980, the event pulled together researchers, utility engineers, and manufacturers of boilers and turbines to share their ideas and experience. A variety of potential solutions were already being tested across the country. Five years later, when utilities had had time to experiment further with SPE remedies and to see some results, EPRI organized a second workshop.

Last summer EPRI held its third SPE workshop, which confirmed that control of the SPE problem may well be within the industry's reach. According to Barry Dooley, technical adviser to EPRI's Generation and Storage Division, "We will definitely be able to solve this particle erosion problem with the tools we have available now." Getting to this stage has not been easy. Today's "tools" are the product of numerous experiments that have helped identify and quantify the problem and of tireless efforts to test potential solutions in laboratories and utilities across the country.

Starting at the source

When the SPE problem first was identified in the industry, the immediate response was to go directly to the source—the boiler tubes—to combat it. Some utilities report great success with boiler-based solutions. But as solution options have evolved over the years, it has become clear that boiler remedies may not always be the most economical answer.

The most widely used boiler-based remedy for SPE is chemical cleaning. It is typically less expensive and more convenient than the two other approaches that have been used, which involve applying a high-chromium-content surface to boiler tubes. (In general, the lower the chromium content of the tubes, the faster oxidation occurs.) However, if boiler tubes in a particular unit are in need of replacement anyway, then high-chromium tubes may be cost-effective. A high-chromium surface can resist scale formation and exfoliation for decades, whereas a chemical cleaning will have to be performed every five or six years.

The chemical cleaning process involves flushing boiler systems with a chemical solvent. When successful, it can remove tens of thousands of pounds of magnetite. Some utilities have found the process even more effective when followed by a steam or air "blast." This helps dislodge magnetite particles that may be trapped in elbows and bends. According to industry estimates, a first chemical cleaning of a 500-MW unit today will cost roughly $1 million. Subsequent cleaning will run about a quarter of that sum, since the first-time expenses include engineering and design work needed for temporary pump and piping systems.

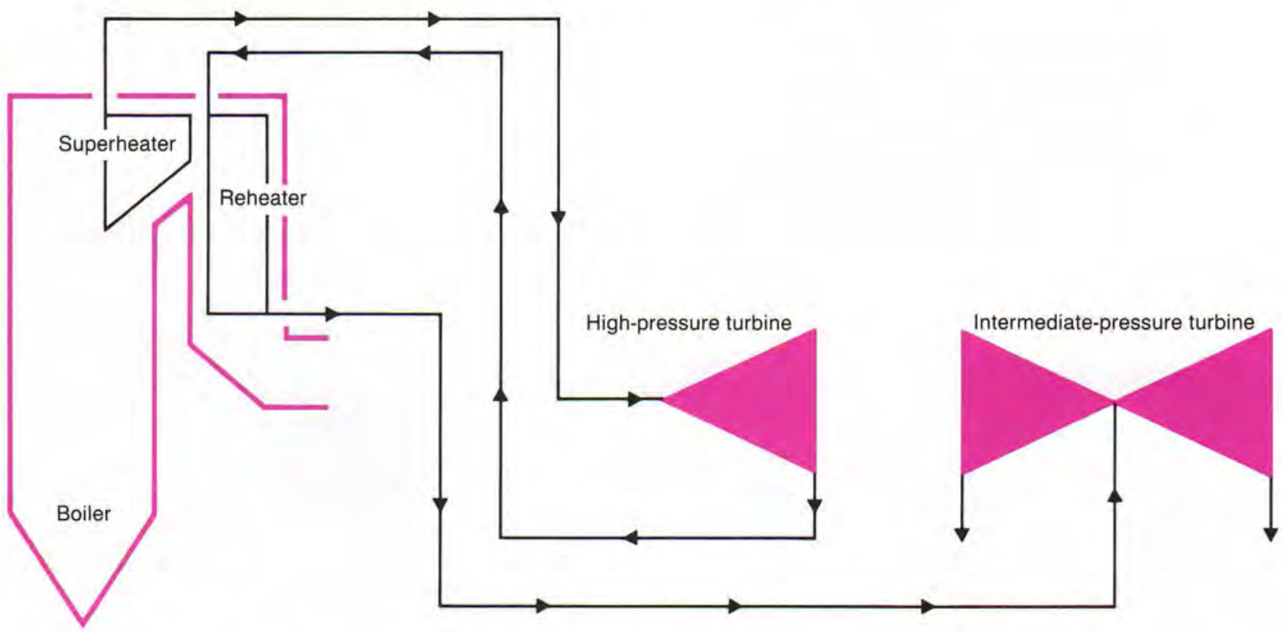
One big expense factor utilities have encountered with this option is the escalating cost of disposing of hazardous wastes. Another recent deterrent has been the increasingly stringent federal, state, and local regulation of such disposal. Potomac Electric Power Co. (PEPCO) spent $1 million on disposal costs alone for the chemical cleaning of two units totaling 1150 MW at its Morgantown station in the past two years. Andris Bilmanis, senior project engineer at PEPCO, said the utility opted to hire a disposal contractor even though the state of Maryland allowed it to treat and then discharge the waste. The problem was that the state did not offer any guidelines on the levels of hazardous materials considered safe to discharge. "We were not comfortable with that," Bilmanis says. "We didn't want to get into a situation of doing something that could be held against us. So we decided to play it safe." In all, the chemical cleaning of the two units cost $5.6 million, including one-time design and engineering expenses for the temporary piping and pumps.

Such temporary systems, which pump the chemical solvent into utility boilers, must be designed to maintain a specified flow rate and temperature as the solvent is circulated for a number of hours. The design and engineering needed for these systems can be quite complex. Industry experts suggest utilities should expect to spend at least one year planning for the project.

Another utility that has relied on chemical cleaning is New England Electric System. Over the past 12 years, NEES has cleaned four boilers a total of seven times. "We have the process down to a science now," says Ed Brailey, Jr., consulting engineer at the utility. He explains that NEES has been able to avoid the high expense of disposal because the organic chemical solvent used can be neutralized in its waste system and discharged. The metals collected through the cleaning are precipitated in the process. Chemical cleaning has retarded the scale growth in NEES's boilers enough to extend the former two-year period between turbine overhauls to

The Path of Destruction

Flakes of magnetite that have their origin in the boiler's superheater and reheater tubes are transported by the steam during startup and blasted at high velocity into the turbines, where they can severely erode turbine blades. Since the flakes shatter into smaller, less destructive pieces once they strike turbine components, problems are most common in the first stages of the high- and intermediate-pressure turbines.



five years. While the cleaning has not eliminated SPE, Brailey says, "it's under control now."

Recent innovations that make chemical cleaning more efficient and effective are being added to EPRI's *Manual on Chemical Cleaning of Fossil-Fueled Steam Generation Equipment* in a major revision of the section on cleaning superheaters, reheaters, and steam piping. The new edition is intended to help dramatically reduce first-time costs. It also will provide utilities with a detailed specification for assistance in working with chemical cleaning contractors. The new manual is expected to be published this year. EPRI's plan is to use the guideline in a field demonstration of chemical cleaning sometime next year.

While there are numerous examples of chemical cleaning throughout the industry, the application of high-chromium surfaces in boiler tubes is far less common. The two variations of this SPE remedy, known formally as chromizing (for new boilers) and chromate treatment (for existing tubes), are based on the same principle: that a high-chromium metal will significantly retard scale formation and exfoliation.

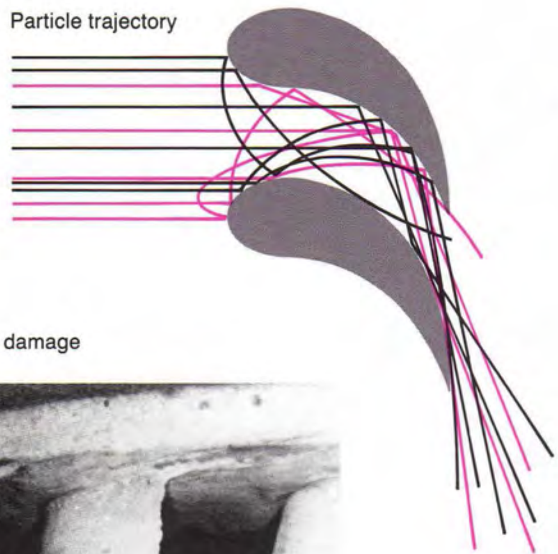
Chromizing was first developed in the late 1970s by Babcock & Wilcox (B&W) and Alloy Surfaces Co. of Wilmington, Delaware. Performed off-site by the manufacturer, the high-temperature process creates a surface that is actually fused into the original metal. The outer layer is a chromium-rich carbide containing about 80% chromium. This lies over a slightly thicker chromium-diffused layer of 16% to 20% chromium. Chromized tubes are intended to resist flaking for the life of the boiler. According to B&W, in laboratory tests these surfaces have survived without exfoliation for the equivalent of more than 80 years at a metal temperature of 1050°F on the inside walls of tubes.

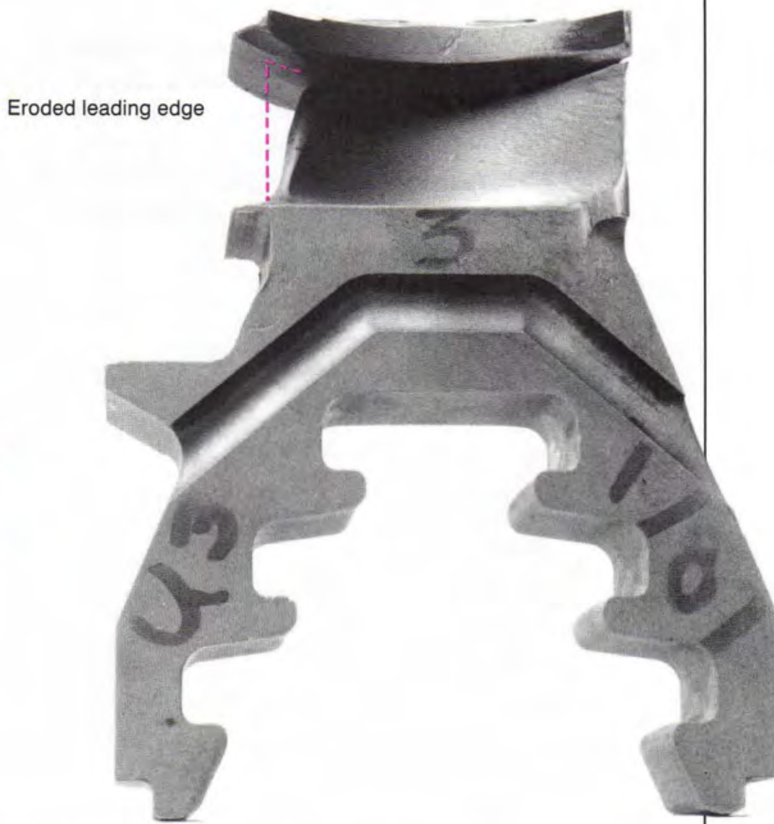
An Ohio utility that chromized all high-temperature tubing and steam piping in a 623-MW unit in 1982 reports that in the following six years of operation, during which the unit ran for 35,230 hours and experienced 845 startups, the turbine suffered only "minor degradation" in performance. Comparative units at the same utility with only one-third the number of startups suffered a "sharp drop" in turbine efficiency between 14,000 and 34,000 hours, the utility reports. Chromizing at this utility cost about $1.5 million. According to industry estimates, a chromized boiler will cost about 20% more than boilers with traditional metal surfaces and about 20% less than stainless steel boilers with a 12% chromium content. So far, B&W reports, the chromizing process has been fully employed in four utility boilers in the United States and partially employed in about half a dozen others.

The chromate treatment process for ex-

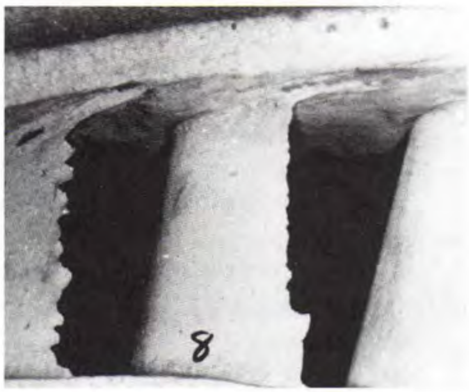
The Impact on Blades

Solid-particle erosion can wear away metal to the point that entire blade rows must be replaced every couple of years. While the damage is often most obvious at the leading edge of the blade, trajectory studies have shown that the trailing edges also suffer significantly as particles ricochet from neighboring blades.





Trailing-edge damage



Coating blades with a thin layer of chromium carbide provides erosion protection that can last five years or more. In an EPRI-patented robot-controlled plasma spray process, the coating starts out as a powder but becomes semimolten as it passes through the electric arc of the spray applicator. The process creates a surface at least 10 times more erosion-resistant than conventional blade materials.

isting boiler tubes, developed in the late 1970s, has been applied in only one utility boiler. A major drawback has been its expense. This process is performed on-site after a thorough chemical cleaning of boiler tubes. A chromate salt solution is injected into the boiler system and circulated for about 48 hours at 580°F and 1000 psi. The resulting surface contains about 50% chromium and retards the rate of scale growth by a factor of three. The estimated cost for this treatment, including the chemical cleaning, is about $2.5 million for a 700-MW unit. If the project involves coating the reheater section, the cost may be higher, since this section may not be designed to withstand the high pressures required for the process.

Steam path innovations

While many U.S. utilities were busily pursuing boiler-based remedies in the early stages of SPE exploration, a second category of potential solutions began to emerge—those aimed at controlling magnetite particles in the steam path. One proposed method of reducing particles in the steam path is the use of a bypass system. Bypass systems have been employed primarily to achieve quicker startups. Many European utilities, at which SPE is virtually unknown, have been using them for decades.

In theory, it makes sense that a bypass system—which transports steam around the turbine during startup—would help alleviate SPE. After all, as EPRI's experiments have shown, the concentration of magnetite particles peaks during startup, measuring 100 to 1000 times that of regular operating conditions. In real life, however, the advantage of a bypass system with regard to SPE has been difficult to prove because most bypass systems have been used in Europe in conjunction with European-manufactured turbines, which themselves appear to be more resistant to SPE.

The importance of turbine design in managing SPE, implied by the European experience, was not recognized early on. Little more than a decade ago, SPE was perceived exclusively as a boiler-related problem, and the idea that turbine design might play a major role was met with much skepticism in the field. Studies reported at the EPRI–ASME conference in 1980 broke new ground, concluding that "the intimate design of the steam path itself is the main factor" in SPE. Today there is a clear recognition throughout the industry—even by North American turbine manufacturers—that the geometry of the path steam follows through a turbine can make a difference. The two U.S. turbine manufacturers have even developed design modifications to reduce the severity of SPE.

Westinghouse Electric has introduced new blade and nozzle designs for the control stage. The new rotating blade design incorporates a blunt leading edge, the angle of which has been matched to that of the inlet steam flow. The new nozzle design includes a contoured end wall in place of the traditionally straight end wall. This shifts the area of high particle impact to a thicker portion of the nozzle and avoids direct impact on the trailing edge. According to Westinghouse, the new designs have contributed to a significant reduction in SPE after more than three years in service. Specifically in the primary arc, the trailing edges of the nozzles retained their original shapes and dimensions, and damage to the leading edge of the rotating blade was minimal.

General Electric, meanwhile, has found that increasing the axial spacing between the nozzles and the buckets can reduce the rebounding of particles as they pass through the turbine. According to GE, the increased clearance allows more time for the steam to accelerate the particles as they pass from the nozzles to the buckets. As a result, they are less likely to rebound. GE's tests found that the benefit of axial spacing decreases as pressure in the unit decreases.

Utilities have considered other methods of controlling particles in the steam path, such as the use of separators and screens to capture magnetite particles. However, studies performed by GE under an EPRI contract showed that most of the particles are very small, measuring about 10 mils or less. Using a screen grid small enough to capture these particles is likely to cause extreme pressure drops, the study concluded.

Still, EPRI has not abandoned the possibility of alternative techniques to remove particles from the steam path. One potential solution now being explored is the use of a centrifuge in the natural bends of system pipes. Because magnetite particles are more dense than steam, the flakes will tend to travel in a straight line, gathering on the outer diameter of the centrifuge. The steam flow, meanwhile, would follow a curved path through the middle of the centrifuge.

There are also some operational changes that have been used to mitigate SPE. One example is the use of full-arc steam admission, where steam is fed into the turbine through all of the control valves. Traditionally, most U.S. units have relied on partial-arc admission during startup because it is more efficient. But it also results in higher steam velocities and higher particle concentrations in the first valves opened, causing significant SPE. With full-arc admission, velocities are reduced and particles are spread more evenly because all valves are opened simultaneously.

Many utilities have switched to full-arc admission at the same time that they adopted other means of combating SPE. At PEPCO, for instance, Morgantown Unit 2 was shifted to full-arc admission after its first chemical cleaning in 1988. A recent inspection of the turbine indicated that while there are still some particles coming through the system, there has been a definite heat rate improvement, amounting to cumulative savings of $3.5 million in fuel costs and operation and maintenance costs over six years. The shift is believed to have helped alleviate the SPE problem in that unit. But as those familiar with the case point out, it's virtually impossible to determine the extent to which full-arc admission helped reduce SPE.

"I think that's what's plagued us as we've gone down the road," says Brailey of NEES. "We're never comparing apples and apples. There are so many darn variables that you've got to look at the whole picture and just make the best call you can." Another difficulty in measuring success is that it takes so long to see the results of a potential solution at a given unit. Many utilities faced with solving pressing SPE problems often can't wait around for the outcome.

"This is not like the computer industry, where things change every six months," says Tom McCloskey, manager for steam turbines and related auxiliaries at EPRI. "It might take three to five years before we know if a specific technique has worked!"

Recent developments

Among the more recently developed remedies for SPE is the use of protective coatings on turbine parts. While similar coatings have been used in aircraft jet engines for some time, significant interest in the use of coatings in utility turbines has emerged only in the past five years.

The coatings are strictly protective, not preventive, and function much like bulletproof vests, shielding their wearers from potential harm. In the words of Jim Edmonds, program manager for rotating machinery at EPRI, "The coating is the last line of defense, and it's a very effective defense mechanism." While coatings are only a temporary solution, many utilities have found they are the most cost-effective remedy for the short term. The protection generally lasts about five years.

The turbine coatings most widely used by utilities today are those applied by a plasma spray process and those that involve a diffusion alloying technique. A third, more recently developed technique, known as electrospark deposition (ESD), is also being used on a smaller scale. ESD is a type of welding process that involves the transfer of molten droplets of coating material from an electrode to the surface of the part through a series of minute electric arcs. As yet, ESD is not usually an economically competitive option.

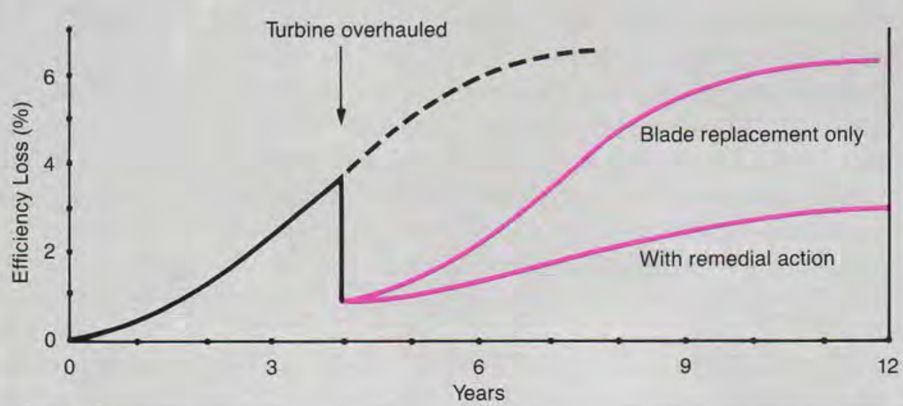
The plasma spray process, a "line of sight" procedure, is typically used to apply a chromium carbide coating to turbine parts (like diaphragms and rotor blades) whose surfaces are visible from 4 inches away, the application distance. The coating starts out as a powder, which assumes a semimolten state as it passes through the arc of the spray applicator. To ensure optimum cohesion, the surface of the part is grit-blasted before the application. The diffusion alloying process takes place inside a retort, which makes it especially useful for coating turbine parts (like nozzle blocks and boxes) whose surfaces are not visible from 4 inches away and cannot be coated effectively with a plasma spray. Typically, diffusion alloying is used to apply a chromium boride surface. The alloying takes place at a high temperature when elements like chromium, boron, and tantalum, in gaseous form, are injected into the retort.

While the plasma spray technique adds a definite coating to the turbine parts, ranging up to 13 mils in depth, the diffusion alloying process actually fuses the new surface to the metal, adding only a very thin surface, usually about 1 mil deep. In laboratory tests diffusion-alloyed surfaces have been found to offer up to 30 times the erosion resistance of standard turbine parts, while the best plasma sprays offer about 10 times the resistance of uncoated turbine parts. However, one difficulty experienced with diffusion alloying has been the bowing or twisting of metal parts due to the high temperatures involved in the procedure.

Under contract with EPRI in the mid-1980s, General Electric developed a plasma spray coating and application process. The process and the coating material are now patented by EPRI. Tests both in the laboratory and in the field have shown that where the impingement an-

The Impact on Efficiency

Solid-particle erosion causes a gradual decline in turbine efficiency—typically about 1% annually—which often costs utilities several million dollars a year in additional fuel and maintenance. As this example indicates, periodic maintenance overhauls bring performance back into line, but degradation begins again at about the same rate. Remedial actions at the time of blade replacement, such as chemical cleaning of boiler tubes or coating of turbine blades, can slow down efficiency losses considerably, and combinations of these actions provide even more effective protection.



gles of the magnetite particles are smaller than 60°, the erosion resistance will be even greater than the 10-fold better performance mentioned earlier. EPRI's coating is unique in part because its application involves a heating process that alters the grain structure of the metal, making it harder and more resistant to erosion. EPRI's plasma spray also is applied in an open-air environment, as opposed to the inert-gas environment typically used with other plasma sprays. The open air encourages higher oxidation, which results in a higher-level chromium content in the final coating. Finally, to ensure an even, high-quality surface, the EPRI coating is applied by a robot.

So far, EPRI's coating has been applied at nearly two dozen utilities across the United States. Because the earliest of these applications took place only two years ago, no actual field results are yet available. But the Tennessee Valley Authority (TVA), which has applied the EPRI coating to components in two of its turbines in the past two years, reports success on a shorter-term problem through the use of a similar chromium carbide plasma spray coating offered by Sermatech International. (Sermatech is also licensed to apply the EPRI coating.)

TVA decided to try the Sermatech coating on one valve plug in a 650-MW unit after successive valve plug problems. Last October the skirt pieces of one plug caused $135,000 in damage when they flew into a turbine. Normally, the plugs that see the most wear last an average of 18 months, explains Orval F. Karr, mechanical engineer for TVA; some last only through one startup. But after one startup and four days of operation, the TVA valve plug coated by Sermatech showed no wear in an area that normally would have been scarred by grooves, Karr says.

Among the utilities with the most extensive experience with turbine coatings is Southern California Edison. SCE has experimented with coatings since the late 1970s. Currently it has more than 50 sets of parts in service that are protected by some sort of coating, including diffusion-alloyed iron chromium boride, plasma-sprayed chromium carbide, and tungsten carbide. None of the systems used to date have been able to completely eliminate erosion. But utility officials report that the coated turbine components maintain higher performance levels for longer periods of time. The use of coatings has helped SCE extend the period between overhauls on its reheat units from four to six years.

Certainly the use of coatings alone will never eliminate SPE, since the sandblasting effect of the magnetite particles ultimately will wear them away. As EPRI's Barry Dooley puts it, "Coatings are not the panacea and can only be regarded as palliatives." When used in combination with other SPE remedies, however, coatings help provide a prevention mechanism that can last for the life of a unit. In fact, EPRI's experts view the combination of turbine coatings and routine chemical cleaning as the most effective, economical solution available today for existing units. This combination appears to be the optimum approach, Dooley says, pointing out that with a thorough chemical cleaning every six or seven years, the coatings would have to be applied only once in the lifetime of a unit.

Through its current package of SPE activities, including the ongoing projects with blade coatings and the upcoming chemical cleaning demonstration, EPRI is working to refine this combination option. In another effort in this area, EPRI intends to explore techniques for applying coatings on-site, so that turbine components do not have to be dismantled and transported to the location of the coating applier. In situ applications could save weeks of outage time.

Meanwhile, additional tools may be helpful for utilities installing new units. Some in the industry have expressed a need for the development of a generic computer code similar to the codes GE and Westinghouse use for design modifications in their turbines. The generic code could be used to evaluate the geometries of the steam flow in any given turbine to determine—before any investment is made—whether that turbine is susceptible to SPE. The code also could be useful in evaluating turbines in existing units to determine whether design modifications would help alleviate SPE.

While the findings in the decade of experience since the first EPRI–ASME workshop have offered the industry some definite direction on the path to controlling SPE, it is clear that determining the best, most cost-effective solution for each unit still remains, to a large degree, a site-specific task. For this reason EPRI plans to put together a handbook to aid utilities in selecting the best SPE solutions for their units. Expected to be published within two years, the handbook will contain a comprehensive set of guidelines based on the most current information available.

Experts are confident that the remedies now available will mean the end of the industry's SPE ills. "Because of the cooperative effort among utilities, manufacturers, and EPRI, we have the solutions now," says McCloskey. "The best retrofit approaches have been identified and will be working their way into operating plants over the next five years. But even more encouraging, the redesigned turbines will be available in time for the next surge of utility orders, and that should nail the problem for good." ■

Further reading

Solid Particle Erosion of Steam Turbine Components: 1989 Workshop. Proceedings for RP1885-6, prepared by ENCOR-America, Inc. September 1989. EPRI GS-6535.

Erosion Resistant Coatings for Steam Turbines. Final report for RP1885-2, prepared by General Electric Co. September 1987. EPRI CS-5415.

Manual on Chemical Cleaning of Fossil-Fueled Steam Generation Equipment. Final report for RP1608-1, prepared by Sheppard T. Powell Associates. January 1984. EPRI CS-3289 (in revision).

This article was written by Leslie Lamarre, science writer. Technical background information was provided by Tom McCloskey, Barry Dooley, and Jim Edmonds of the Generation and Storage Division.

TECH TRANSFER NEWS

Textile Office Opens at North Carolina State

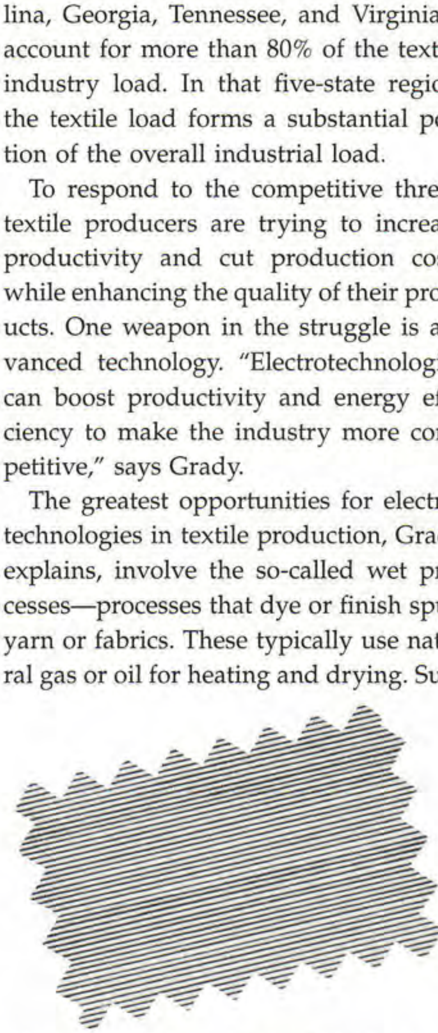
EPRI's newest R&D applications center aims to strengthen the U.S. textile industry's competitive edge by helping develop and commercialize electrotechnologies that boost productivity and product quality. The EPRI Textile Office, which opened this year at North Carolina State University's College of Textiles, will coordinate all of the Institute's textile-related research and serve as a bridge between utilities and their textile industry customers.

The office will perform three broad functions, according to Ammi Amarnath, project manager for process industries in EPRI's Customer Systems Division. "We are developing collaborative R&D and demonstration projects for the textile industry, promoting technology transfer to EPRI member utilities and their customers in the textile industry, and providing educational and technical support. This support involves courses, seminars, and conferences relating to specific technologies for the textile industry."

Textile manufacturing has traditionally been a labor-intensive process. The entrance into the global market of overseas companies employing low-cost labor has put the U.S. textile industry at a competitive disadvantage, according to Perry Grady, professor and associate dean of the College of Textiles, who has been named director of EPRI's Textile Office. The possibility of foreign manufacturers displacing a portion of domestic production poses a threat to regional economies, as well as to utilities that supply power to textile firms. The U.S. textile industry consumes more than 25 billion kWh of electricity per year. While this amounts to only about 3% of the total U.S. industrial load, Amarnath notes, in some parts of the country, especially the Southeast, the textile load is significant. Five southeastern states—North Carolina, South Carolina, Georgia, Tennessee, and Virginia—account for more than 80% of the textile industry load. In that five-state region, the textile load forms a substantial portion of the overall industrial load.

To respond to the competitive threat, textile producers are trying to increase productivity and cut production costs while enhancing the quality of their products. One weapon in the struggle is advanced technology. "Electrotechnologies can boost productivity and energy efficiency to make the industry more competitive," says Grady.

The greatest opportunities for electrotechnologies in textile production, Grady explains, involve the so-called wet processes—processes that dye or finish spun yarn or fabrics. These typically use natural gas or oil for heating and drying. Sub-



stituting electricity for fossil fuels would speed up the processes while saving energy and space, and it may improve product quality as well. Several projects are already under way to develop and demonstrate promising electrotechnologies. "We're working on radio-frequency and infrared drying of fabrics," says Grady, "as well as ultrasound dyeing, which improves the penetration of dye into fabrics and has great potential for reducing energy consumption."

The new office will give EPRI a regional presence in the heart of the textile industry, Amarnath points out. "Establishing the office in Raleigh puts us close to the textile industry and to the utilities that serve it," he says. "We selected North Carolina State University's College of Textiles because it is a national leader in this field. About half of all U.S. textile graduates are products of NCSU." The college will soon open a new $33 million textiles education and research building with a model manufacturing facility for demonstrating the latest textile production technology. ■ *EPRI Contacts: Ammi Amarnath, (415) 855-2548, and Perry Grady, (919) 737-7550*

Decision Tool for Hydro Relicensing

During this decade the licenses of some 300 hydroelectric plants will expire, presenting many utilities with the challenge of relicensing units in compliance with a body of new legislation that dictates whether and how a hydro facility can be operated. One new ruling in particular has raised a dilemma. The Electric Consumers Protection Act (ECPA) mandates that relicensing applicants give equal consideration to power and nonpower values of water resources when developing alternative relicensing strategies; that is, the value of electricity produced by a hydro unit must be weighed against environmental, recreational, irrigational, flood control, and other values associated with the reservoir and its tributaries. The water's value as a wildlife habitat must be considered, for example, as well as its value for fishing and boating. The intent of the legislation is to develop relicensing alternatives that provide the greatest overall public benefit. The dilemma utilities face is that the ECPA doesn't specify just how such equal consideration is to be achieved.

Recognizing the need of hydro utilities for a tool to tackle the issue, EPRI worked

with Decision Focus to develop a methodology that addresses the trade-offs in a logical, explicit, and objective manner. The methodology is described in a recently released EPRI report, *Evaluation of Hydro Relicensing Alternatives: Impacts on Power and Nonpower Values of Water Resources* (GS-6922). The methodology uses cost-benefit analysis to rank alternatives according to net societal value. The idea is to quantify the impact of each alternative on power and nonpower values—or, in other words, quantify the change in benefits to society—and then identify the alternative with the largest net value to society.

While cost-benefit analysis is often used for evaluating hydro projects, the new methodology goes a step further by employing decision analysis techniques to assess the potential uncertainties in the values. This helps a utility determine the value of gathering additional information to resolve the uncertainties.

The new approach has already paid off. In case studies the EPRI methodology helped three utilities identify relicensing options that would ultimately increase the net value of the water resource to society. For one plant the net value could be enhanced by $900/kW, primarily because of greater recreational use of the reservoir as well as greater power values.

The EPRI methodology also has won the endorsement of the Federal Energy Regulatory Commission. According to Fred Springer, director of FERC's Office for Hydropower Relicensing, the EPRI methodology "provides applicants with an additional tool to examine their relicensing decisions and to assist in their relicensing proposals."

Still, EPRI and Decision Focus staff caution that the methodology is not a panacea. "This isn't a cookbook for decision making," says Jim Birk, director of the Storage and Renewables Department in EPRI's Generation and Storage Division. "Rather, it's a guide to help utilities make considered decisions about relicensing." ■ *EPRI Contacts: Jim Birk, (415) 855-2562, and Chuck Sullivan, (415) 855-8948*

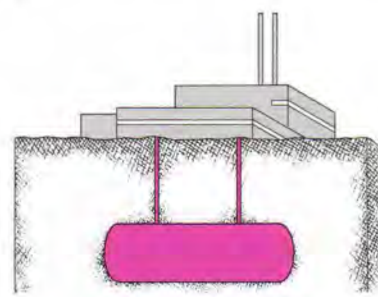
Underground Tank Strategies

Utilities with underground storage tanks may find valuable information in two new EPRI reports intended to help them meet federal controls on tank operation. About 15,000 underground tanks are used by the utility industry to store gasoline, diesel fuel, oil, and other materials. Storing fuels underground has its advantages: the risks of explosion and vandalism are reduced, and land surface can be used more efficiently. But buried tanks and their piping can fall victim to corrosion and structural failure, which may lead to leaks that can be difficult to detect and expensive to clean up.

In December 1988 the Environmental Protection Agency finalized new regulations placing restrictions on underground tanks and their piping systems. For example, the regulations require many tanks to be equipped with safeguards such as anticorrosion and leak detection systems; they also mandate schedules for repairing, upgrading, or closing tanks.

To help utilities better understand the new requirements and comply with them in a cost-efficient manner, EPRI researchers have analyzed the regulations and explored alternative compliance strategies. This information is presented in a series of reports covering such topics as state and local regulatory trends, monitoring technologies, remediation technologies, and decision-modeling tools that enable utilities to select optimal tank management strategies.

The most recent report in the series, *Release Detection for Underground Storage Tank Piping Systems* (GS-6906), is a reference manual that describes the technical requirements and timetables for installing leak detection systems for piping and presents three types of systems that comply with the EPA regulations. "Adequate leak detection minimizes the risks associated with operation of underground storage tanks," says Mary McLearn, a project manager in EPRI's Generation and Storage Division. "Choosing which techniques to use depends on the type of tank and piping, cost, and such site-specific factors as depth to groundwater. This report will help utilities understand the options available for leak detection on tank piping."



Many of the underground tanks currently in operation require retrofitting to comply with the new standards, and those that leak will have to be brought up to standard or closed. *Repair, Upgrade, and Closure of Underground Storage Tanks* (GS-6830) reviews the regulations and examines options that utilities can use in designing strategies to comply with the standards while minimizing costs and out-of-service time for individual tanks. ■ *EPRI Contact: Mary McLearn, (415) 855-2487*

Fossil Plant Waste and Water Management

Measuring Trace Metals in Aqueous Discharges

by Winston Chow, Generation and Storage Division

ABSTRACT *A 24-laboratory study determined the performance of inductively coupled plasma (ICP) atomic emission spectroscopy in measuring 14 elements in typical power plant waste streams. The laboratory data were used to define the ICP method's measurement variability and to compute the limit of detection for each element in each type of water or wastewater sample. These limits were then compared with published EPA detection limits. In addition, the performance of the ICP method was compared with that of conventional graphite furnace atomic absorption methods. This work will help in setting reasonable plant discharge requirements and in defining appropriate applications for the ICP method.*

Under the Federal Water Pollution Control Act of 1972, the electric power industry is required to monitor its aqueous plant discharges for a number of chemical constituents. As a result of a 1976 consent decree (*Natural Resources Defense Council* v. *Train*), the U.S. Environmental Protection Agency (EPA) was required to establish effluent limitation guidelines, pretreatment standards, and new source performance standards for 65 pollutant classes specifying 129 priority chemical pollutants.

Recent years have seen attempts by permit-granting agencies to use the detection limit of a given analytical method as the limit for the discharge of one or more priority pollutants. This trend makes it necessary to better understand the performance of various aqueous monitoring methods.

In anticipation of tightening requirements for utilities to monitor their plant discharges for some or all of the priority pollutants, EPRI initiated a research project (RP1851) with a twofold objective: to collect data on the frequency of occurrence and the concentration of these chemicals in utility power plant aqueous discharges, and to assemble a set of chemical sampling and analysis guidelines for the substances of most interest. Utility chemists and environmental directors would then have a firm basis for selecting appropriate methods to monitor those substances in plant discharges.

Analytical methods qualification

Early studies on the precision and accuracy of various EPA-specified analytical methods for measuring trace metals indicated that method validation was often based on tests using water samples and pollutant concentrations not representative of power plant discharge streams. The lack of a comparable independent database derived from utility-specific laboratory testing of the methods on plant water and wastewater samples placed individual utilities at a disadvantage when responding to proposed plant siting and permitting requirements. Moreover, the situation was exacerbated by the trend toward setting effluent pollutant concentration limits on the basis of EPA's Water Quality Criteria, many of which are defined at or below the detection limits of currently available methods for chemical analysis. To deal with these constraints, EPRI instituted an analytical methods qualification (AMQ) field study.

The primary objective of the AMQ study is to define the capabilities and limitations of conventional methods used to measure selected chemical constituents in utility discharge streams. The required analytical performance data were collected through interlaboratory round-robin testing, primarily at volunteer utility laboratories. Results on the detection limits and precision of various methods obtained in this way provide a more realistic estimate of the capabilities of EPA-approved methods, especially under permit compliance monitoring conditions.

The AMQ study is divided into four parts. This arrangement has enabled the greatest number of volunteer laboratories to participate and also has permitted modification of the test design in response to changing environmental concerns or new regulatory initiatives. Early AMQ efforts evaluated various atomic absorption spectroscopy techniques in measuring 10 trace metals in utility water and wastewater streams. The results of these tests are reported in EPRI CS-5910, Vols. 1 and 2. This article focuses on a recently completed AMQ study using inductively coupled plasma (ICP) atomic emission spectroscopy.

ICP results

The ICP study investigated 14 trace metals in representative power plant water/wastewater samples. The trace metals were selected on the basis of importance to the utility industry, regulatory interest, and discharge levels. They were aluminum (Al), barium (Ba), beryllium (Be), boron (B), cadmium (Cd), chromium (Cr), copper (Cu), iron (Fe), lead (Pb), manganese (Mn), molybdenum (Mo), nickel (Ni), vanadium (V), and zinc (Zn).

The types of water/wastewater used in the tests were as follows: a quality assurance/quality control sample acquired from the EPA's Quality Assurance Laboratories in Cincinnati; spiked reagent-grade water prepared in the EPRI contractor's laboratory; river water; seawater intake and discharge; ash pond overflow discharge; and treated chemical-metal-cleaning waste. The last four samples were collected from actual power plant streams.

Samples containing the 14 chemical species were sent to the participating volunteer laboratories for analysis by the ICP method. This method, including the sample preparation and digestion steps, is specified under EPA Method 200.7. For each sample, duplicate measurements were requested.

Each volunteer laboratory had its own ICP instrument. A laboratory's qualifications were ascertained by means of a survey that asked about the lab's experience with the instrument and the frequency of use; the background and experience of the operator(s); and general laboratory practices associated with trace chemical species measurement. Only laboratories with experience and good lab practices were selected for the study. A total of 24 qualified.

An important performance index for laboratory analytical methods is the limit of detection (LOD) of a particular method in measuring a given chemical species. In essence, it defines the method's ability to determine the presence of the species in a sample. The computations for deriving the LOD are dependent on a number of variables, including the type and complexity of the sample, the precision of sample preparation, and the ability to preserve the species from sample digestion through the instrument analysis steps. The complexity of the sample is a particularly crucial factor: it is considered to be a key contributor to variations in a method's LOD.

In Figure 1, results from EPRI's interlaboratory round-robin study on the ICP method are compared with the EPA-specified limits of detection for the 14 trace metals of interest. The sample in this case was ash pond overflow extracted from an actual coal-fired power plant. The EPRI-derived LODs were in approximate agreement with the EPA specifications for only 4 of the 14 species: cadmium, chromium, copper, and molybdenum. For the other 10 species, the EPRI LODs were much greater than the EPA's. In a number of instances, they were one to two orders of magnitude higher. For example, at 534 micrograms per liter, the EPRI LOD for vanadium was nearly 70 times greater than the EPA value of 8 micrograms per liter.

To a large extent, the differences can be attributed to the complex water quality characteristic of a power plant ash pond. Nominally, the EPA LODs were derived by using potable or distilled water spiked with a single chemical to a concentration as high as several hundred milligrams per liter. In contrast, the concentrations of trace elements found in water and wastewater streams at electric generating stations are generally less than a milligram per liter and typically in the micrograms-per-liter range.

The results of this and the other AMQ work are especially important for defining reasonable requirements for plant discharge monitoring and effluent permit compliance. And there is another benefit from this project. The ICP results can be compared with the earlier results on various atomic absorption spectroscopy methods in order to select the most appropriate method for a given chemical and application. For instance, Figure 2 presents the chromium detection limits of the ICP method and of graphite furnace atomic absorption spectroscopy (GFAAS) for four types of utility aqueous streams. The GFAAS method is shown to be superior to ICP for monitoring

Figure 1 EPA-specified limits of detection for 14 trace metals are compared with LODs derived from EPRI-sponsored tests that applied the ICP (inductively coupled plasma) method to an ash pond overflow sample from a coal-fired power plant. The diagonal line represents agreement between the two sets of LODs. EPRI's interlaboratory studies of analytical methods under realistic monitoring conditions are providing important data for defining reasonable plant discharge requirements.

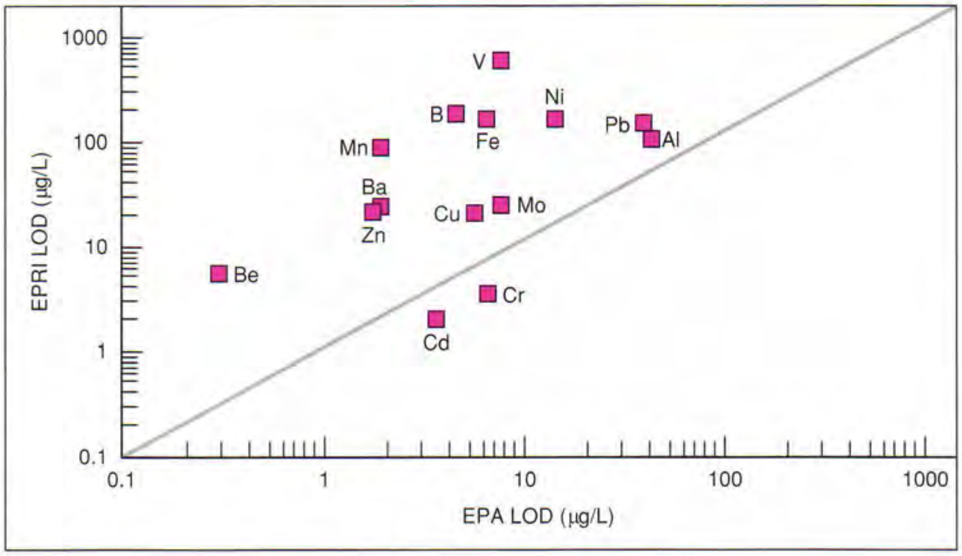
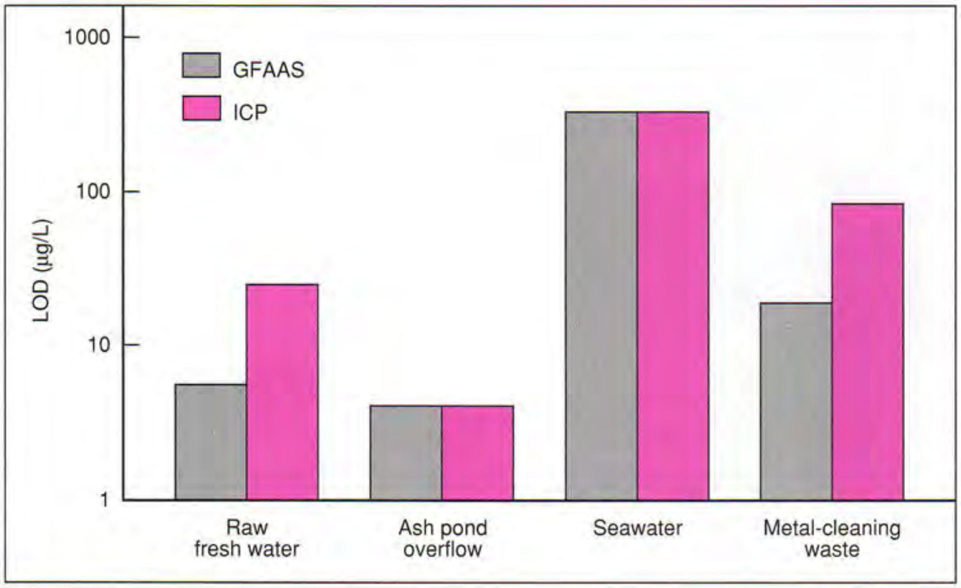


Figure 2 Chromium detection limits of the ICP (inductively coupled plasma) and GFAAS (graphite furnace atomic absorption spectroscopy) methods for four types of utility aqueous streams. By making such comparisons possible, EPRI's test program is helping utilities select the appropriate analytical method for a given monitoring application.



chromium in raw fresh water and in treated chemical-metal-cleaning waste, while the two methods are comparable for ash pond discharge and seawater samples. These results reaffirm ICP's capabilities as a tool for rapid trace-element-screening functions. But they also underscore that for the accurate measurement of low-level trace species, it is necessary to consider—among other factors—the effects of sample complexity and chemical interferences.

The ICP results will be published this winter. Also, in response to a broadening regulatory emphasis on trace metals, another round-robin series of tests is scheduled to begin this winter. It will use the GFAAS method and will include the elements aluminum, antimony, beryllium, manganese, molybdenum, silver, and thallium. Utilities interested in participating in this effort should contact Winston Chow, (415) 855-2868, or Babu Nott, (415) 855-7946.

Atmospheric Sciences

Acid Deposition Model Evaluation

by D. Alan Hansen and Peter K. Mueller, Environment Division

EPRI and several partners—the U.S. Environmental Protection Agency, Environment Canada, the Ontario Ministry of the Environment, and the Florida Electric Power Coordinating Group—are midway through a precedent-setting collaborative program to evaluate acid deposition models. The midway point will be marked by the publication of a report by the U.S. government's National Acid Precipitation Assessment Program (State of Science/Technology Report 5: *Evaluation of Regional Acidic Deposition Models*).

One of 28 reports supporting the NAPAP assessment, SOS/T Report 5 will include the results of a preliminary performance evaluation of the foremost American and Canadian acid deposition simulation models, RADM (Regional Acid Deposition Model) and ADOM (Acid Deposition and Oxidant Model), respectively. Three other reports will deal with the science of modeling.

The evaluation activities reported here are based on comparing model outputs with observed values. These serve in part as tests of the science embodied in the model. But deviations also could result from differences in spatial representation between simulated and measured values, and they further depend on proven specifications for measurement accuracy and precision. Deviations could also stem from inadequacies in model inputs that determine, for example, initial and boundary conditions; emission strengths and locations; and the weather conditions that govern the chemical processing and physical movement of materials in the atmosphere. All these factors need to be taken into account.

The evaluation is preliminary in that in the limited time allowed by the NAPAP publishing schedule, only a small fraction of the field data collected could be used and only a small fraction of the tests for comparing model simulations with those data could be run. A much more thorough evaluation will be completed over the next two years.

The overall model effort has been expensive. Upon its completion, the program sponsors will together have spent over $20 million on model development and over $35 million on gathering observational data for evaluating the models. As large as these sums are, they pale in comparison to the billions of dollars in costs the models potentially can save if used to develop effective emission control strategies for mitigating acid rain and dealing with other air quality issues.

Further, as surrogates for reality, the models can be used to answer such questions as these: To what extent will emissions from a given source be transformed in the atmo-

ABSTRACT *To ensure that the capabilities of acid deposition simulation models are well characterized, EPRI has embarked on a collaborative program of field studies and model evaluation with U.S. and Canadian regulatory agencies and the Florida Electric Power Coordinating Group. Initial results from a comparison of a subset of the field data with model simulations will soon appear in a report published by the National Acid Precipitation Assessment Program.*

sphere and deposited at a given receptor? What is the transboundary flux of pollutants between the United States and Canada? What will be the cumulative exposure at a given receptor in response to a particular emission scenario? There simply are no other practical means available for answering such questions.

Program background

In the early 1980s, the EPA and the Canadian agencies separately committed to developing acid deposition models for application to emission control policy analysis. At that time, EPRI strongly advocated that the models be evaluated before their application, so that measures of confidence—and the associated risk—could be placed on their predictions. The government agencies agreed with this position, and joint planning for evaluation protocol development and field study design began in early 1986.

Given the scope and collaborative nature of the program, it was necessary to establish a complex management structure. A bilateral steering committee of high-level managers from the government agencies and EPRI was charged with resolving policy issues. To make the disparate program elements operate as a cohesive whole, a project management group with one representative from each sponsor was formed; each member has direct responsibility for managing his organization's model evaluation-related activities. To support the project management group in conducting the program and establishing the quality of the data collected, four teams of experts were assembled—one each on emissions, routine measurements, research and aircraft measurements, and model evaluation. Finally, an external review panel of international experts on various aspects of the program was established to periodically review the effort and provide counsel on its direction and progress.

Having determined that the acid deposition modeling teams newly organized by the EPA and the Canadians were of exceptional quality, EPRI decided that its resources would be best utilized not by embarking on a separate model development effort, but by undertaking three complementary activities:

- Contributing to RADM and ADOM parity by focusing on known model deficiencies considered important and removing them by improving the relevant process representations
- Comparing the performance of key RADM and ADOM modules (e.g., those for gas phase chemistry, cloud processes, dry deposition, and transport) and of the integrated models
- Participating in the interpretation of model evaluation results derived from comparisons of field data with model outputs

Since the model developers were exploring new ground in terms of computational techniques and the scope of process representations, EPRI considered it essential that at least two distinct models be nurtured to provide a means for sorting out the relative merits of alternative approaches. The first two activities supported this goal.

Preliminary results

To provide measurements on a variety of atmospheric materials for the operational eval-

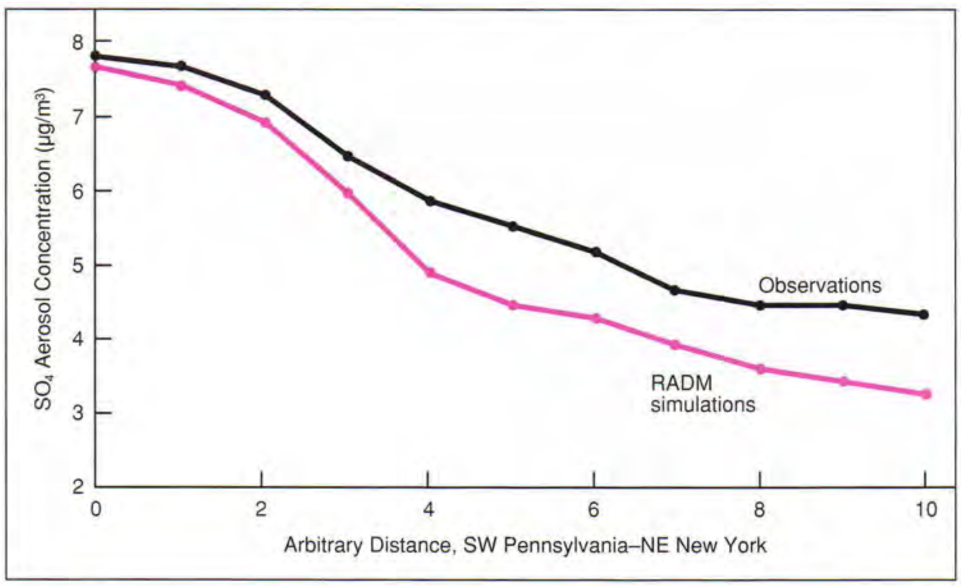
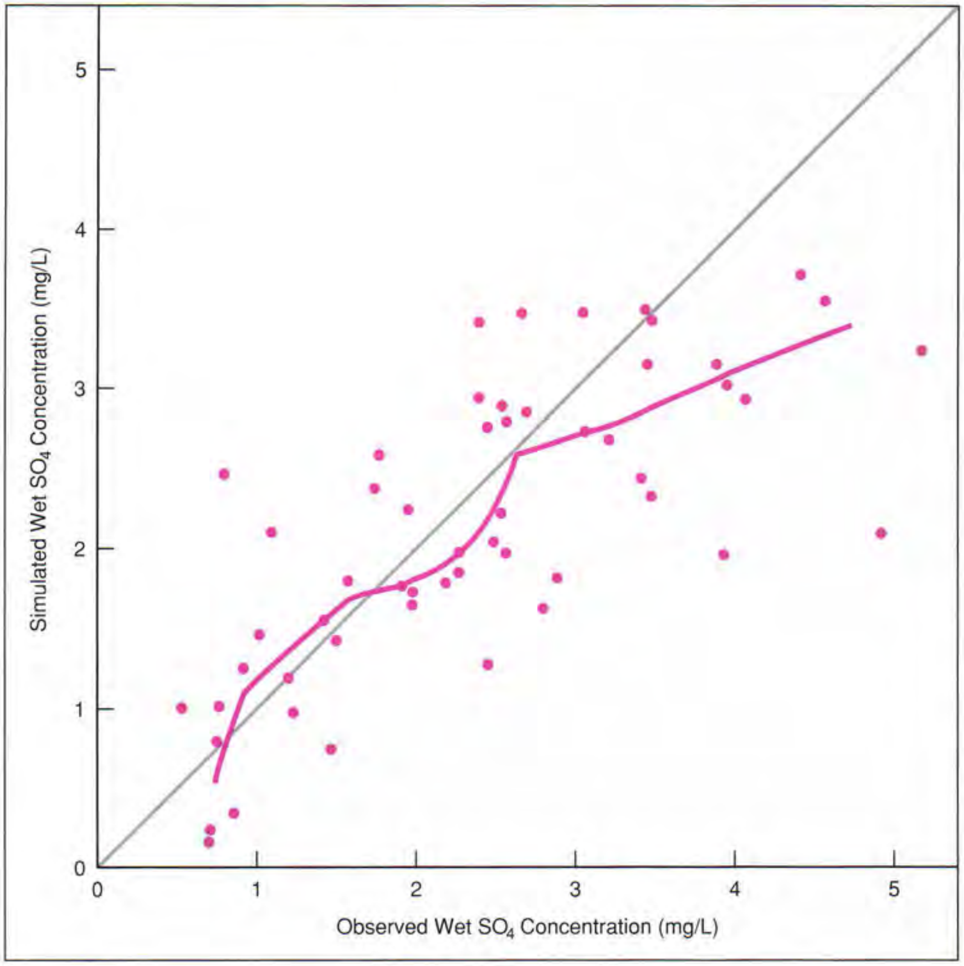


Figure 1 Observed and simulated average sulfate aerosol concentrations for September 1988 for a series of sites across Pennsylvania and New York. Field data from these and other sites are being used in a comprehensive effort to evaluate acid deposition models. In this comparison, the model—a version of RADM featuring six vertical layers—tends to slightly underestimate the concentration and overestimate the spatial gradient.

Figure 2 Model simulations versus field observations for precipitation-weighted average wet sulfate concentrations for September 1988. A complex statistical technique was used to produce a smoothed running median (color) that indicates the central tendency over increments of the compared values.



uation of the models—as well as to define seasonal and (to some degree) interannual variability and geographical diversity—approximately 100 stations were set up throughout the eastern United States and southeastern Canada and operated from June 1988 through May 1990. For the most part, sites were selected to avoid urban and local source influences.

In addition, in the summer of 1988 and the spring of 1990, both the Canadian agencies and the EPA conducted intensive, six-week measurement campaigns involving the use of several aircraft and the taking of research-grade measurements at a limited number of surface locations. These intensive studies were designed to provide data for diagnostically evaluating the models.

A formal protocol for the preliminary model evaluation on behalf of NAPAP was drafted by the EPA and its contractors and then reviewed and approved by both the model evaluation team and the external review panel. For technical and practical reasons, only a portion of the protocol could be implemented in time for the results to be included in SOS/T Report 5. Nonetheless, that work constitutes the most extensive evaluation to which regional air quality models have ever been subjected. Examples of the types of comparisons used in the assessments to date are discussed below.

A relatively dense cluster of sites across Pennsylvania into New York was designed to confirm and define strong gradients expected in pollutant deposition patterns. Using data from these sites for September 1988, the monthly average particulate sulfate concentrations observed along a line from southwestern Pennsylvania to northeastern New York were compared with simulations made by a six-vertical-layer version of RADM (Figure 1). For this period, the model had a slight tendency to underestimate the concentration of sulfate and overestimate the spatial gradient.

For another kind of test—comparisons of time series of spatially averaged observations and model simulations—sites were grouped on the basis of spatial and temporal coherence of initially collected field data. At this level of spatial aggregation, the simulations closely tracked the temporal variability of the observations, although there were some differences in the absolute values. This indicates that the models are treating large-scale meteorology—which is the dominant contributor to temporal variability—well.

A final example of how model simulations and field observations have been compared is given in Figure 2, where the monthly average (September 1988) sulfate concentration in rain for each station is plotted. The diagonal line would result from exact correspondence between the observations and the simulations. The irregular line is a smoothed running median of the values. Although the large scatter is illustrative of the inherent variability in data on rain composition, there is little bias between the simulated and observed values except at the higher observed values, which the model tends to underestimate. Analyses are under way to explain this behavior.

Many more comparisons were run; other compounds investigated include sulfur dioxide, nitrogen dioxide, nitric acid, and hydrogen peroxide in air and nitrate in rain. The results indicate that for the month selected in the summer of 1988, the models simulated some aspects of atmospheric behavior well and others not so well. Additional, more comprehensive evaluations using the complete two-year data set will shed considerably more light on model performance characteristics and the reasons underlying them. In the meantime, although there is ample room for improvement, the models embody the best science available: within the established bounds of their uncertainty, they are the best tools available for acid rain amelioration assessments.

Nickel-Iron Battery Pilot Plant

by Robert Swaroop, Customer Systems Division

Through its Transportation Program, EPRI has for the last 10 years been pursuing the development and commercialization of reliable and cost-effective electric vehicles (EVs). The major factor impeding the development of a broad-based market for EVs has been the unavailability of propulsion batteries that exceed the performance and life capabilities of today's state-of-the-art lead-acid batteries.

During the past seven years, Eagle-Picher Industries (EPI) has been actively involved in developing a propulsion battery for EV applications that will overcome the limitations of lead-acid technology. This effort has resulted in the development of the 6-volt NIF 200 module. In comparison to a lead-acid battery, this nickel-iron battery provides a considerably greater specific energy, which translates into EVs with greater range.

The primary application of the NIF 200 is to power the Chrysler TEVan—an electric minivan based on the popular Chrysler Voyager/Caravan series—which will have an urban driving range of approximately 100 miles. The NIF 200 also holds promise for the electric G-Van, a large van based on the GMC Vandura. Substituting the NIF 200 for the standard lead-acid battery used in the G-Van would increase the van's range by approximately 55% and thereby increase its market potential. Taken together, the G-Van and TEVan applications could represent a substantial market for the NIF 200.

The pilot plant objectives are as follows:

- To develop an efficient process for fabricating the NIF 200-series battery on a large-volume production scale, while focusing on quality control, iron and nickel electrode production, and cell and module assembly
- To build a pilot-scale NIF 200 battery plant that is capable of manufacturing 500 batteries per year and that can be expanded to produce 1000 batteries per year if warranted
- To gain experience and develop the manufacturing technology required to establish a plant capable of producing 10,000 or more batteries per year

The primary manufacturing technology partner will be EPI, which will provide the initial technical know-how. The pilot plant will be located in a facility operated by EPI in Joplin, Missouri. A plant with a production capacity of 500 batteries per year will require 25,000 square feet. In order to expand production to 1000 batteries per year, an additional 5000 square feet will be required. The layout of the pilot production facility is shown in Figure 1.

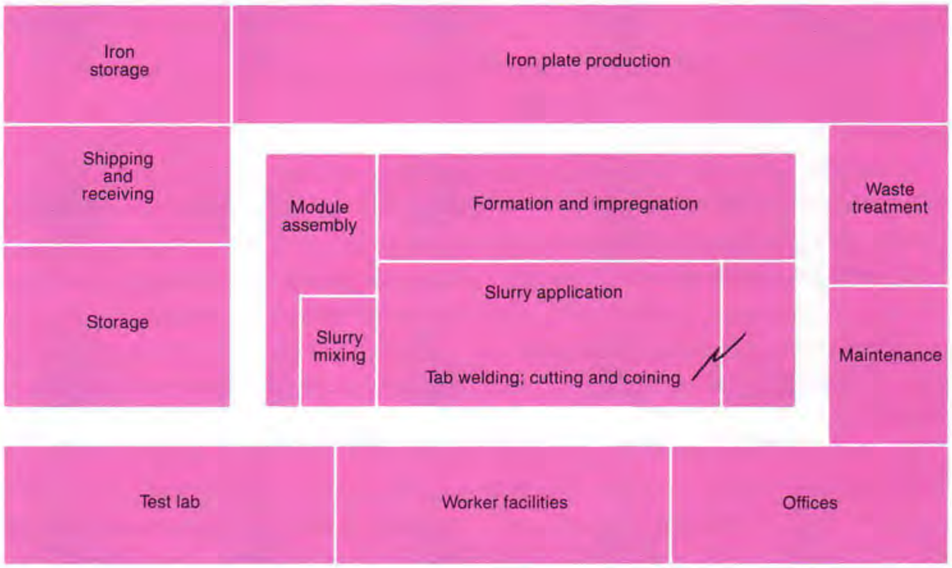
There are certain manufacturing processes that have yet to be perfected. The most important is the fabrication of the iron electrode, which involves the transfer of technology from NiFe-AB of Sweden. While such transfers are often problematic, in this instance the transfer is expected to progress relatively smoothly because EPI has been working with NiFe-AB for the last three years to learn this technology.

The manufacture of NIF 200 modules is virtually pollutant- and toxicant-free. The process does not emit any air pollutants, and the only by-products that require special handling are sodium nitrate and nickel nitrate. These materials will be stored in special containers and transferred to a company in Pennsylvania for purification.

Quality control will be a major consideration in the production of the NIF 200. Statistical standards of acceptance will be established for materials and components bought outside as well as for those produced in-house. Once these standards are in place, components will be randomly selected and tested for conformity to the design characteristics EPI has outlined. Statistical process controls will also be implemented to ensure compliance during the impregnation, material mixture, assembly,

ABSTRACT *The NIF 200-series nickel-iron battery is the product of an eight-year research effort; now that the technology has been developed, the building and operation of a pilot plant represents the next stage in the commercialization of the NIF 200 as a propulsion battery for electric vehicles. The goal in establishing a pilot plant will be to develop efficient manufacturing processes and also to develop the capability to manufacture 500 to 1000 NIF 200 battery systems per year. The project is cofunded by EPRI, South Coast Air Quality Management, and Southern California Edison.*

Figure 1 The planned nickel-iron battery pilot plant. This production facility represents the next step in the commercialization of an advanced battery that promises greater range for electric vehicles.



and final testing stages.

The installation and startup of the 500-battery-per-year pilot plant will encompass an 18- to 24-month period. Because it is anticipated that market demand may increase significantly, the pilot plant may operate for only five to seven years, after which a separate, larger facility may be necessary. The demand for NIF 200 is obviously correlated with the availability of suitable vehicle bodies. Production is expected to start in the fall of 1991 for the G-Van and in 1994 for the TEVan. The latter date corresponds to the beginning of regular vehicle production for the new model year. A limited number of demonstration G-Vans and prototype TEVans will be built before these dates for field evaluation purposes. General Motors has agreed to produce sufficient G-Van bodies as demand develops, and negotiations are proceeding with Chrysler for beginning the production engineering process.

The TEVan will require NIF 200 batteries, and some of the G-Vans produced between 1991 and 1994 may also require NIF 200 batteries, depending on the success of that battery in the G-Van. If adequate demand for these vehicles materializes, there may be a critical need for constructing a battery plant capable of producing at least 1000 batteries per year by 1994. With success, the post-1994 demand for the TEVan—and therefore the NIF 200—may expand even further. In addition, the use of the NIF 200 in G-Vans and in nonhighway applications (such as golf carts, materials movers, forklifts, and airline vehicles) would greatly increase the rate of sales growth. If demand for the NIF 200 battery grows rapidly, plans may have to be developed for enlarging the battery production capacity soon after the decision is made to launch the pilot plant project.

Advanced Fossil Power Plants

Fuel Cell Commercialization

by Edward Gillis, Generation and Storage Division

Fuel cells offer several attractive features for the generation of electricity in urban areas. These include:

- High efficiency (over 50%) at full and part power and in small-sized plants (2–10 MW)
- Very low levels of emissions—i.e., for NO_x, SO_x, and reactive organic compounds combined, less than 0.1 lb/MWh
- Compact, low-profile configurations with low audible noise and dry cooling towers (no vapor plumes) to facilitate siting
- Factory-assembled modules with a short construction time
- Operating flexibility, including rapid electrical transient response, cogeneration potential, and unattended operation

In recent years, the leading advocates of fuel cells within the utility industry have been municipal utilities. They believe that much more fuel cell capacity could be installed and operated in urban areas than other, currently available thermal or engine-driven capacity. Furthermore, they believe that this in-city generation would complement the existing generation and transmission grid and be an economical alternative to its expansion.

With this in mind, a group of municipal utilities, in collaboration with the American Public Power Association (APPA) and EPRI, initiated a study of the market requirements that fuel cells would have to meet in order to penetrate the public power market. The study also sought to characterize the factors in decision making in public power utilities that would most influence purchase decisions, and to quantify the public power market for fuel cells. The results of this study were published in January 1990 as EPRI report GS-6692.

Using preliminary results from the study, the group of municipal utilities and EPRI collaborated with APPA to issue a notice of market opportunity (NOMO) to the worldwide fuel cell

ABSTRACT *A nearly two year effort by EPRI, the American Public Power Association, and representatives from a group of municipal utilities has culminated in the development of a shared risk–shared benefit fuel cell commercialization plan that is being endorsed by all segments of the utility industry. The process used to develop a plan acceptable to manufacturers and utility users may provide a model for other technologies as well.*

R&D community in November 1988. In addition to providing market information, the NOMO reflected the utilities' interest in sharing with manufacturers the costs and risks of introducing fuel cells into this market. This was not an offer to sponsor R&D or conduct demonstrations endlessly; rather it asked interested manufacturers to provide information about their commercialization plans and to propose how utility organizations might invest in the process to make a more appropriate product available more quickly.

Many manufacturers replied that their technology had not progressed to the point that they could accurately define their product, schedule, and commercialization program in the depth asked for by the NOMO. However, five manufacturers from Europe, Japan, and the United States provided comprehensive replies. From the utility side, a review team composed of representatives from 10 utilities, APPA, and EPRI participated in a dialogue with these five manufacturers to better understand and evaluate their commercialization plans and judge the benefits of utility participation. The following evaluation criteria were used:

- Power plant specification
- Simplicity of design and technology
- Timing of commercial availability
- Mature life-cycle costs (capital and O&M)
- Program financial requirements
- Team's experience
- Architect/engineer involvement and one-stop responsibility
- Scope of supply
- Responsiveness to NOMO
- Corporate commitment and risk strategy

Throughout these discussions, the review team was prepared to endorse several, one, or none of the commercialization plans provided by the manufacturers. In December 1989, the team unanimously endorsed the plan put forth by Energy Research Corp. (ERC) to commercialize a nominal 2-MW internal reforming molten carbonate fuel cell (MCFC) power plant.

MCFC commercialization plan

The technical specifications of ERC's 2-MW plant are summarized in Table 1. The plant is attractive for in-city applications; it is a compact, low-profile system with an efficiency of over 50% and excellent part-power and environmental characteristics. It is also a mechanically simple atmospheric pressure system (Figure 1) that promises high reliability in addition to its other features.

ERC's commercialization plan involves the construction of one or more demonstration model plants and a total of 100 MW of early production units in the United States. Additional demonstration and early production units will be constructed simultaneously for installations in Europe. The plan attempts to balance the technical and financial risks and incentives between ERC and the utility participants, as suggested in the NOMO. Before utilities invest in the construction of 2-MW demonstration plants, ERC must achieve specific technical milestones in a 100-kW pilot plant currently being constructed at a Pacific Gas and Electric facility and must have letters of intent for the procurement of early production units. These letters of intent contain agreed-on requirements for scope of supply, price, performance, and warranties. They become firm commitments and require the payment of deposits when the 2-MW demonstration plant achieves specific operational milestones. From the utility viewpoint, these conditional commitments serve to place a ceiling on the price of initial units; demonstrate utility interest in the product; and minimize the risk that the program will terminate in the demonstration phase.

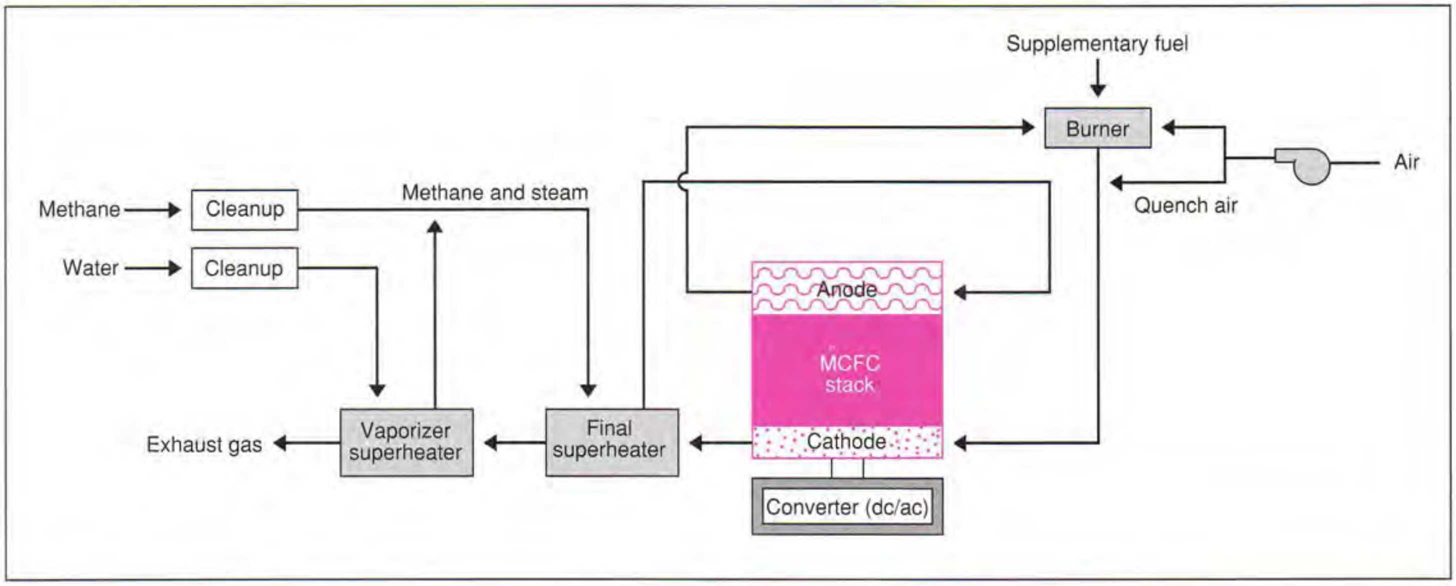
ERC's portion of the financial risk is to fund the construction of a small-scale manufacturing facility to produce components for the demonstration units, and to prepare the detailed engineering design for the demonstration and early production units. These actions have been initiated by ERC. A further prerequisite for confirming the letters of intent is that ERC construct a commercial-scale manufacturing facility to fill the orders for early production units. Utilities have two incentives for participating in the demonstration and early production phases of the commercialization program: they are to be directly involved in the power plant design, and they are to receive royalties from the sale of future commercial

Table 1
ERC MOLTEN CARBONATE FUEL CELL OFFERING

	Design A	Design B
Power plant rating (MW)*	1.77	1.77
Efficiency, lower heating value, at rated load (%)	60	54
Heat rate, lower heating value (Btu/kWh)	5700	6300
Footprint (ft^2)	5500	4500
SO_x and NO_x (lb/MWh)	0.0023	0.0034
Water requirement (gal/h)	0	110
Cost ($/kW)	1300	1000
Waste heat at rated power (Btu/kWh)	775	1100

*The plants can operate continuously at 125% of rated load at these heat rates (lower heating value): 6640 Btu/kWh for Design A and 7000 Btu/kWh for Design B.

Figure 1 Internal reforming MCFC power plant. The atmospheric pressure operation and minimal complexity of the Design B system promise high reliability in addition to improved efficiency and emission characteristics.



units totaling approximately twice the capital investment they have at risk.

The 10 utilities that participated in the NOMO process do not, by themselves, represent a sufficiently large market to commercialize this fuel cell. Additional utility companies representing the private and cooperative sectors of the industry were invited to hear details of the commercialization plan. This resulted in the formation of the Fuel Cell Commercialization Group by utilities from all sectors of the industry. The group's key objectives are to further increase the number of utility participants and to proceed with the activities in accordance with the plan developed. The Fuel Cell Commercialization Group held an industrywide briefing in Dallas, Texas, this past September to seek additional participants.

EPRI's role

ERC has been EPRI's principal molten carbonate fuel cell developer since 1982. A compact, efficient dispersed generator was the initial development goal, and several design studies of 2-MW units (EM-3307 and EM-4179) helped guide the technology development. As a sponsor of this technology, EPRI reviews its status continually.

EPRI is also a sponsor, along with Pacific Gas and Electric and the California Energy Commission, of the project to design, construct, and operate a 100-kW MCFC pilot plant at PG&E's San Ramon, California, facility. The performance of this pilot plant is one of the key milestones triggering construction of the 2-MW demonstration model plants.

EPRI will take a lead role in helping member utilities assess and manage the risks of participating in demonstration and early production model plants. Its activities will include applying proven design analysis techniques, such as UNIRAM, STAMP, and failure mode and effect analyses; conducting periodic technical and cost reviews of plant design, manufacturing, and construction efforts; reviewing quality assurance plans; and documenting demonstration plant experience via site engineers-of-record.

Fuel cell applications

Many of the utilities that have joined the Fuel Cell Commercialization Group plan to install their units on distribution system substations. At these sites, the fuel cell can be an alternative to expensive transmission line upgrading or substation expansion in response to load growth in specific locations. A single 2-MW fuel cell occupies approximately the same area as a tennis court. Many substations have sufficient space for more than one fuel cell, thereby ensuring reliable service through plant redundancy. An added benefit of the fuel cell power plant—the result of the solid-state power conditioner's ability to continuously adjust power factor—is reduced losses in the substation and hence an increase in its peak capacity.

Other utilities anticipate cogeneration applications. In certain instances, this use can permit the deferral of transmission and distribution expansion as well as yield revenues from the sale of thermal energy.

Several utilities are exploring the operation of fuel cells on landfill gas, which has methane (CH_4) and carbon dioxide (CO_2) as major constituents. Molten carbonate fuel cells are particularly well adapted to use this renewable resource as a fuel. For one thing, CO_2 is a reactant in the MCFC; hence this gas mixture actually improves fuel efficiency. Also, since the 2-MW MCFC is an atmospheric pressure system, minimal compressor energy is required to transport or use the fuel. And a 2-MW plant or a small number of plants are appropriately sized for this resource, since most landfills do not produce methane at high rates. Environmental considerations also make this option attractive. Both CO_2 and CH_4 are greenhouse gases, and in certain areas of the country, pollution regulations require that landfill gas be harvested because CH_4 is a smog precursor. If such regulation spreads to other parts of the country, as is likely, the

MCFC should be seriously considered as a means to profitably utilize this fuel.

The longer-term application for MCFCs is integration with coal gasifiers in central station power plants. These plants promise the highest efficiency (over 50% and conceivably as high as 60%, coal pile to busbar) and the lowest emissions of any coal-fueled technology yet conceived. However, the technical capabilities and economics of the MCFC must be proved before a large-scale central station power plant is attempted. This proof can be provided at minimum cost in small-scale plants such as the 2-MW unit being commercialized by ERC and the Fuel Cell Commercialization Group members.

Lessons learned

The commercialization plan developed by ERC and the review team is an important product in its own right. The utility industry's enthusiastic response to the plan shows that even though the industry is increasingly risk-averse, it will respond, given the proper product and a balanced risk-reward proposition. This should be welcome news to the developers and manufacturers of other fuel cells and other electrical equipment.

The NOMO document played a key role in establishing a dialogue between the prospective manufacturers and users. In addition, much credit has to be given to the utility staff members who participated in this dialogue; it was a labor-intensive activity with no assurance at the outset of a successful program. The results to date indicate that this process may serve as a path for other new technologies in resolving the chicken-and-egg commercialization dilemma.

Transmission System Design and Operation

Transient Field Data for Improved System Design

by Selwyn Wright, Electrical Systems Division

ABSTRACT *Electrical transients commonly disturb the normal operation of transmission systems and sometimes lead to costly outages. Field data were needed to validate simulation techniques and establish design criteria for the development of improved transmission system protection schemes. A study by EPRI and Florida Power & Light has obtained field data on transients to help engineers design more reliable and cost-efficient transmission lines and substations.*

Electrical transients caused by lightning and switching surges are a common occurrence affecting the operation of transmission systems. These transients stress insulation systems and can produce flashovers, which can result in interruptions of service.

To help utility engineers design improved transmission system protection schemes, field data were needed to validate simulation techniques and to support the development of proper design criteria. EPRI, in collaboration with Florida Power & Light (FPL), has met this need by collecting pertinent transient data. In this project (RP751), EPRI recorded transients and characterized them in terms of rate of rise, magnitude, and frequency. In many cases, the origin of the transient could be determined.

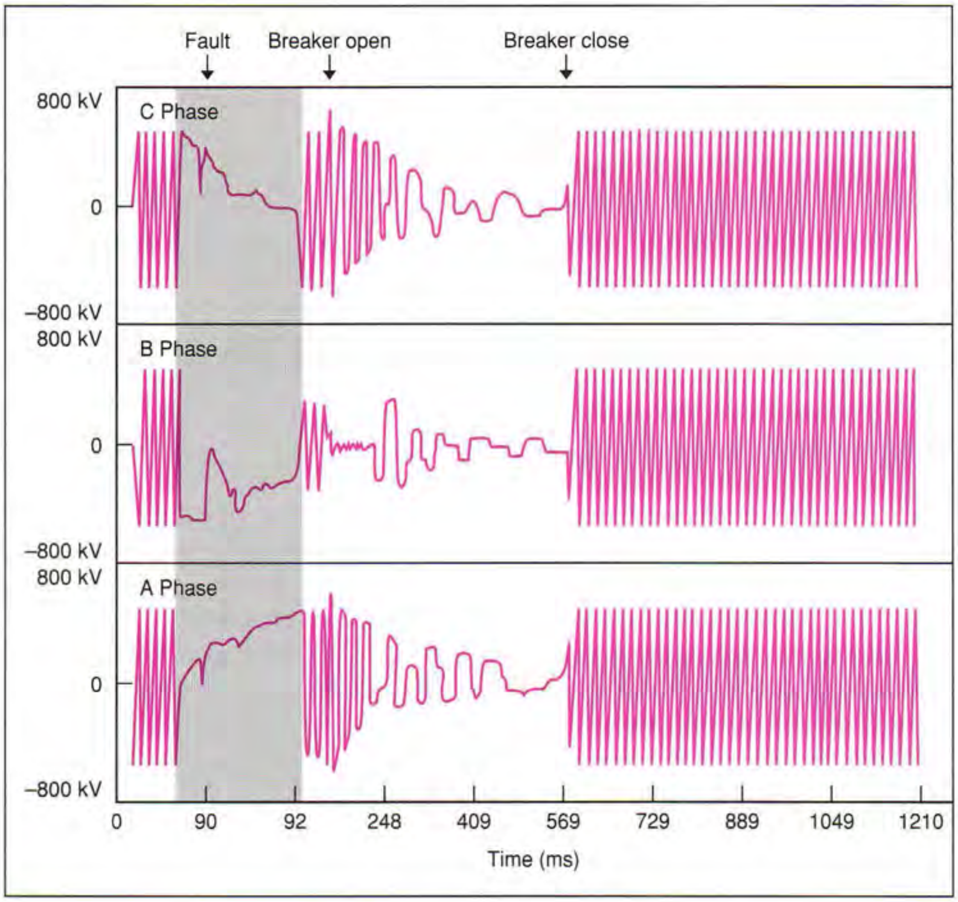
The objective of the study was to compile a database on transmission line transients for use in developing equipment to control electrical surges, designing high-speed relaying systems, and verifying computer models of transients. The study involved the operation of recording laboratories to capture data on naturally occurring transient events, the use of staged switching tests to obtain a statistical sample of actual transient switching overvoltages, and the analysis of the switching-test results and significant naturally occurring events by using a transient network analyzer (TNA).

Automatic monitoring

To provide for the automatic capture and storage of data on power system transients, two mobile monitoring laboratories with a frequency response of up to 100 kHz were designed and built specifically for this project.

Adaptive sampling systems were used to capture transient data with high-frequency content as well as pre- and postevent data with low-frequency content. The systems' sampling rates are adjustable in a range from 2 kHz to 500 kHz. When there is no high-frequency content in the input signals to the recorders, a low, memory-conserving sampling rate is used. When there is a transient, however, the recorders automatically switch to a higher sampling rate; the resulting data ap-

Figure 1 Oscillographic trace of a fault on the B phase. The recorders switch to a higher sampling rate when signals with a high-frequency content are received, creating a trace with an expanded scale (gray band) and clearly capturing the fault transient. This fault occurred on a clear night, with no storms in the area, and was not caused by any overvoltage. Arc extinction can be seen just before the 248-millisecond marker in B phase.



pear on an expanded part of the record. This dual-sampling-rate capability was, at the time of the system development, a major advancement in the process of collecting and analyzing transient field data (Figure 1).

The laboratories were initially installed in two FPL substations, one 500 kV and the other 138 kV. Then, for several years, they were both used to monitor one 120-mile-long 500-kV line. One laboratory was placed in the Andytown 500-kV substation and the other in the Orange River 500/230-kV substation. This made it possible to collect data from both ends of the line simultaneously.

Once the laboratories were in place, the study was conducted in three steps: automatic monitoring, staged switching tests, and TNA studies. In the first step, data on naturally occurring transient phenomena were collected and analyzed. The transient recordings were categorized and summarized to determine which events were significant. The events recorded included primary and secondary line faults, primary and secondary line switching, and direct and induced lightning surges.

In a two-year period, the recording systems captured 447 transient events at Andytown and 277 transient events at Orange River during normal system operation. The majority of the recorded events were caused by induced lightning surges; faults on the secondary system were the next most common source of transients. Neither of these sources caused significant voltage surges on the 500-kV system.

During this two-year period, only two faults were recorded on the monitored line. Both of these faults occurred approximately 46 miles from Andytown. In each case, high-speed reclosing was successful and took place well after the arc had extinguished.

The time it takes for an arc to extinguish is a function of the operating conditions of the system, the location of the fault (because it affects fault current magnitude), and the configuration of the line. For the recorded faults, the arc extinction time was 78 milliseconds when only the transformer was connected and increased to 124 milliseconds when one set of shunt reactors was connected. Both of these times are well within the 0.5-second reclosing time.

Six shielding failures were also recorded during this two-year period. Only one of these was recorded at both ends of the line; the other five triggered only one of the monitoring laboratories. It is notable that no backflash events occurred on the monitored line during the two-year period, although backflashes were recorded at other times. For the transient recorded at both ends of the line, the point of occurrence on the line was calculated, and confirmed from each end, using the traveling-wave method.

Staged switching tests

In the second step of the study, an additional 98 events were recorded during staged switching tests, when the line was energized and deenergized from Andytown a total of 49 times. These tests provided switching-surge statistics for use in the validation of modeling techniques.

Another reason for the staged tests was to determine the effects of removing the preinsertion resistors from the 500-kV circuit breakers and instead controlling the transients with metal oxide arresters. The tests indicated that switching transients can be controlled by using gapless metal oxide arresters.

At Orange River, the transient overvoltages resulting from the staged tests had a maximum value of 1.73 per-unit, with a mean value of 1.47 per-unit and a standard deviation of 0.111. At Andytown, the maximum overvoltage value was 1.50 per-unit, the mean value was 1.19 per-unit, and the standard deviation was 0.136.

Transient network analyzer

In the third step of this effort, TNA studies were conducted and were validated by the field measurements. Additional cases were then studied with the TNA model to predict the effects of removing the resistors under other system conditions. The conditions included the following:

- High-speed reclosing, and variations in the reclosing time, with the reactors connected
- High-speed reclosing without the transformer energized at Orange River
- High-speed reclosing with a 450-ohm pre-insertion resistor, for comparison with the other reclosing cases

The cases without resistors were studied with and without arresters as a further check on the effectiveness of the arresters during switching events. In all cases, voltages were measured at several locations along the modeled line to develop the overvoltage profile. Both phase-to-ground and phase-to-phase voltages were recorded at all locations.

The results of the TNA studies matched the field results from the monitoring period and staged switching tests well. This match validates the modeling techniques and gives the TNA results from the extended studies a high degree of credibility.

Overall, this three-part study has contributed to the understanding of the magnitude and frequency of transients on transmission systems and will help utility engineers design more reliable and more cost-efficient transmission lines and substations. It has also provided valuable information for the development of improved protection schemes, protective relaying devices, switching practices, and circuit breaker equipment.

Control and Information Systems

Certification of Nuclear Plant Training Simulators

by Robert W. Colley, Nuclear Power Division

ABSTRACT *In March 1987, the NRC issued new regulations requiring each operator of a nuclear power plant to demonstrate, either by obtaining approval or by providing certification, that its simulation facility is adequate for the examination of plant operators. By late March 1991, a utility choosing to have a certified simulation facility will be required to submit a certification form to the NRC. EPRI has been conducting research since 1983 on methods for verifying simulator performance. This work provides comprehensive, verified methodologies and procedures for simulator certification.*

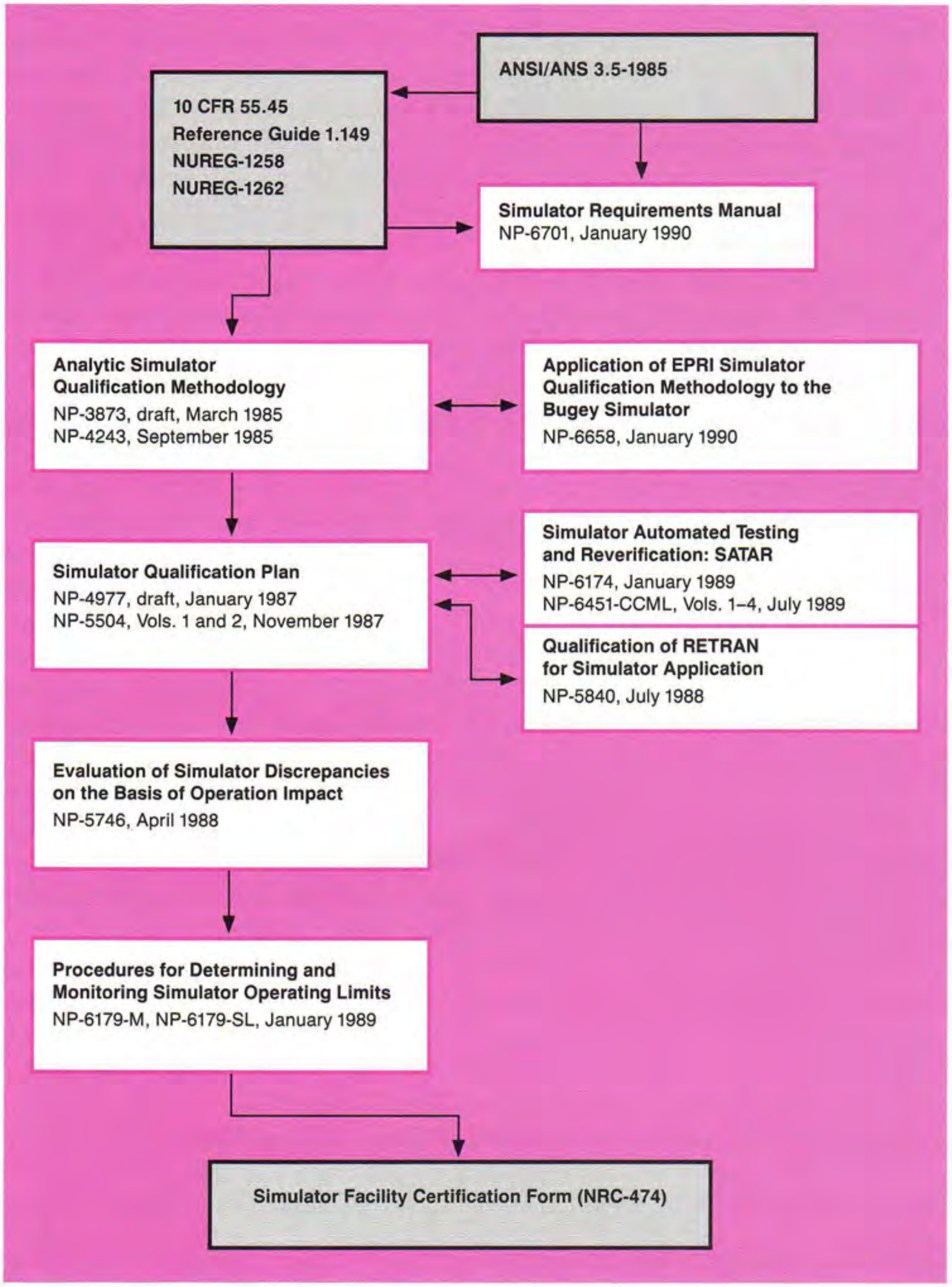
EPRI has produced a series of 11 reports and a software code that define methodologies and procedures for complying with the Nuclear Regulatory Commission's requirements for the certification of training facilities for nuclear power plant operators. Figure 1 presents an overview of the EPRI work, showing the relationships between the various NRC regulations, guides, and standards; the endorsed ANSI/ANS standard; the NRC certification form; and the EPRI reports and code.

The NRC regulations, guides, and standards (as well as the Institute of Nuclear Power Operations guidelines) are described, analyzed, and compared in the *Simulator Requirements Manual* (NP-6701). The objectives of this work were to integrate the documentation and legal requirements affecting the simulator certification effort and to provide guidance to engineering staff developing simulator upgrade procurement specifications.

On the basis of the NRC requirements, EPRI developed a systematic methodology for qualifying the analytical models used in nuclear training simulators by means of engineering codes; it is described in *Analytic Simulator Qualification Methodology* (NP-4243). This methodology was tested and verified. One set of verification tests was performed by Electricité de France at its Bugey simulator. The findings of that verification work are documented in NP-6658. Another report, NP-5840, documents that the RETRAN engineering code—also developed by EPRI—is qualified to provide the best-estimate reference information used as a benchmark for qualifying the simulator's models.

The *Simulator Qualification Plan* (NP-5504) provides procedures for documenting the qualification of a training simulator. The procedures provide detailed, step-by-step instructions; estimates of required resources; docu-

Figure 1 EPRI has produced a series of reports and the SATAR code (color) to help utilities comply with regulatory requirements on the certification of simulators for training nuclear power plant operators.



mentation forms; and demonstration examples. The plan is modular and can be tailored to utilities' existing documentation and resources. This approach includes the use of transient data, such as those provided in NP-5840, for "tabletop" comparison of simulator transient data and reference plant data.

To reduce the effort required to qualify a simulator for NRC certification, the SATAR (Simulator Automated Testing and Reverification) code was developed and documented in NP-6451-CCML. SATAR automatically verifies the dynamic performance of the simulator models by running a sequence of performance tests, collecting and analyzing data, and comparing the results with baseline tests.

The simulator qualification plan identifies the deficiencies and operating limits of the simulator's models. NP-5746 provides a methodology and procedure for evaluating—and prioritizing for correction—the discrepancies found by the qualification plan. The objective of this work was to provide guidance to utilities in order to minimize the impact of discrepancies on plant operation and safety, given finite resources.

Another regulatory requirement that had to be addressed was simulator operating limits. Suggested methods and procedures for determining and monitoring these limits are presented in NP-6179-SL. This document identifies required utility resources, provides alternatives for addressing simulator operating limits, and provides documentation forms for meeting the NRC certification requirements.

Simulator qualification methodology

The objectives of the work documented in NP-4243 were to develop a systematic methodology for qualifying the analytical models used in nuclear training simulators and to establish a set of training-oriented criteria to help utilities respond to NRC regulations on simulator qualification. The simulator qualification methodology is composed of four steps.

The first step is to define the scope of the simulator model qualification. It would not be practical to attempt to duplicate the entire simulator by means of an engineering code. The scope of the simulator model is selected on the basis of training scenarios where dynamic effects are important.

The second step is to develop a matrix of the dynamic modes of the components for each modeled component. This results in a matrix of modes for the components within the scope of qualification. Next, all the transients that can result in excursions into the dynamic modes are listed. A cross-matrix of modes versus transients is developed, and the minimum set of transients that exercise all the modeled component modes is selected.

The third step is to select the critical parameters to monitor. On the basis of the operating procedures and lesson plans for the training session scenarios, the critical parameters that the operator is to monitor and that may initiate operator actions are identified.

The last step is to quantify the critical parameter performance characteristics and criteria against the reference data. The work documented in NP-5840 demonstrates the ability of the RETRAN code to provide the best-estimate reference information for qualifying full-scope nuclear power plant training simulators. Evaluations of 50 PWR and 31 BWR transients demonstrated that essentially all the dynamic states required for qualification of nuclear power plant full-scope simulators were experienced. The criteria for comparison of the simulator model and the reference engineering code included the average difference, the trend (or slope) difference, the extrema differences, the time-to-trip or set-point differences, and the differences in natural periodicity (frequency, amplitude, and convergence). A scale is provided for converting these differences into impacts on training.

Simulator qualification plan

The objectives of the work documented in NP-5504 were to develop, demonstrate, and refine the simulator qualification procedures and to provide sound cost estimates of the resources necessary for a plant-specific qualification program. The result was the development of procedures to evaluate the simulator environment and systems, evaluate the instructor interface, perform simulator test evaluations, and evaluate the configuration management program.

The first set of procedures is designed to evaluate the simulator environment and systems identified in the objectives of the training program, evaluate the scope of simulation, and determine whether the simulator has sufficient physical fidelity. The training objectives for which the simulator is to be qualified are described by the complete set of scenarios used in the operator training or testing program. The objective of the simulator qualification process is to verify the suitability of the simulator to perform these scenarios. The procedures next determine if the simulator models all systems that are required in the performance of the scenarios. The impact on training of not having all the systems completely modeled is evaluated and documented. The last in this group of procedures identifies instances where the location, device type, or labeling of displays, controls, annunciator windows, and other equipment is different in the simulator than in the reference control room.

The next set of procedures provides guidance for the evaluation of the simulator's initial conditions, remote functions, control functions, and other instructor features. The selection of these features is based on the training and testing scenarios as well as on current industry standards. The procedures help develop a schedule of tests of these various functions and provide guidance for evaluation and forms for documenting the results.

The third set of procedures is designed to evaluate the simulator's capability to perform the transient and normal operation scenarios required for the training and testing program. A set of scenarios that exercises all the models is selected, and the performance of the simulator during these scenarios is evaluated. These scenarios are compared with reference plant data or engineering code models, where available. The eight procedures cover selection of test scenarios, specification of performance test criteria, collection of reference data from the plant or engineering code models, collection of simulator data, comparison with reference data, evaluation of simulator performance, and resolution of discrepancies. The SATAR program permits the user to develop and then run automatically a sequence of performance tests and performs the evaluations in support of this set of procedures. The program makes it possible to create files of test-point variables for the comparison of the simulator to the reference plant; creates backup and restore files; collects simulator performance test data; has an interface for the importing of reference data; and performs the analysis and plotting of the test results. It has been estimated that this program will save 400 person-hours per year.

The fourth set of procedures provides a checklist designed to evaluate whether adequate administrative controls exist to satisfy the standards and to ensure that the simulator configuration is kept current with the plant configuration. Changes to the reference plant may affect the ability of the simulator to faithfully reproduce the response or physical appearance of the reference plant. The procedures review the administrative controls for the operational database and ensure that a structured process is in place to identify changes to the reference plant and modifications to the training program that may necessitate upgrades to the simulator software or hardware.

Prioritizing simulator discrepancies

The objective of the work documented in NP-5746 was to help utilities evaluate, and prioritize correction of, simulator discrepancies found during the simulator qualification evaluation. The results were as follows: a methodology for evaluating simulator discrepancies on the basis of operational impact, guidelines for assigning priorities in view of practical considerations, sample test cases that apply the methodology to PWR and BWR training simulators, and training alternatives to simulator model reconstruction or computer hardware upgrading.

Benefits

This comprehensive set of reports uniquely provides flexible and detailed procedures for setting up and executing a simulator qualification program. It has been estimated that the use of the simulator qualification plan alone would save a utility $100,000 in the certification of a nuclear power plant simulator. Other benefits include the following:

- The EPRI simulator qualification reports provide tested estimates of the human resources required to perform the certification.
- Preparation of certification documentation on the basis of this industry-accepted approach may increase the probability of NRC acceptance.
- The use of SATAR can reduce certification and recertification costs.
- Electing to address those simulator discrepancies that have the largest operational impact first can reduce the risk of costly equipment damage or plant outages.

Fourteen utilities have already used the simulator qualification plan, 7 have used the methodology for discrepancy resolution, 7 have used the simulator operating limits methods, and 18 have received prerelease copies of the SATAR software.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Customer Systems		
Nonintrusive Load Monitoring System: Development of Commercial-Sector Application (RP2568-15)	$582,400 39 months	Massachusetts Institute of Technology/*L. Carmichael*
High-Efficiency Refrigeration for Supermarkets in New York State (RP2569-13)	$64,000 9 months	Foster-Miller, Inc./*M. Blatt*
Multifamily Residential Customers: Characteristics and Research Needs (RP2597-25)	$60,100 5 months	Barakat & Chamberlin, Inc./*A. Lannus*
Operational Characteristics of Cold-Air Diffusers (RP2732-35)	$385,200 29 months	Colorado State University/*R. Wendland*
Heat Recovery With Ice Storage Systems (RP2732-36)	$62,900 14 months	Calmac Manufacturing Corp./*R. Wendland*
Assessment of Large Cool Storage Facilities (RP2732-38)	$98,000 12 months	Joseph Technology Corp., Inc./*R. Wendland*
Establishment of an EPRI Pulp and Paper Office (RP2782-12)	$61,600 8 months	Institute of Paper Science and Technology/*A. Amarnath*
Electrical Systems		
Power System Steady-State Stability Monitor: Software Development and Product Support Services (RP2473-43)	$60,900 12 months	Sydetech System Development Technologies/*R. Adapa*
Diagnostics for Studying Oxidation in Cable Insulation (RP2957-5)	$61,600 9 months	University of Connecticut/*B. Bernstein*
System Voltage Stability/Security Assessment and On-Line Control (RP3040-1)	$749,300 36 months	Ontario Hydro/*D. Maratukulam*
Scoping Study of Robotic Manipulator for Vaults (RP3074-1)	$215,900 5 months	Southwest Research Institute/*R. Nakata*
Static VAR Compensation by Energy Flow Routing (RP3155-2)	$50,000 14 months	University of Kentucky/*R. Adapa*
Methods for High-Impedance Fault Detection, Phase 2 (RP3202-1)	$292,100 16 months	Texas A&M Research Foundation/*T. Kendrew*
Environment		
Contemporary and Historical Atmospheric Depositional Fluxes of Mercury: Environmental Significance (RP2020-12)	$226,200 25 months	University of Connecticut/*D. Porcella*
Sensitivity of the TVA Power System to Changes in Climatic Trends (RP2141-15)	$100,000 24 months	Tennessee Valley Authority/*L. Levin*
Neoplastic Transformation of Normal Human Bronchial Epithelial Cells (RP2222-6)	$128,400 12 months	University of Southern California/*W. Weyzen*
Application of Reservoir Science and Engineering to Water Resource Management (RP2932-4)	$71,000 9 months	Murray State University/*J. Mattice*
DNA Adducts and Oxidative Damage as Biological Dosimeters (RP2963-3)	$221,700 20 months	DOE/*L. Goldstein*
Exploratory Research		
Development of Ferritic B/B′ Superalloys (RP2426-20)	$141,200 21 months	Northwestern University/*R. Jaffee*
Surface Modification With Metal Plasma Techniques (RP2426-27)	$414,700 35 months	DOE/*J. Stringer*
Testing and Development of Thermal-Shock-Resistant Ceramics (RP2426-28)	$249,600 22 months	Ceramatec, Inc./*W. Bakker*
Decomposition, Stochastic Programming, Importance Sampling, and Parallel Processors (RP8010-9)	$206,400 35 months	Stanford University/*H. Chao*
Generation and Storage		
Durability Surveillance of Advanced Gas Turbine Engine: Engineering Project Management Planning (RP2774-1)	$88,000 5 months	Fluor Engineers, Inc./*C. Dohner*
Engineering Model of Mixing Processes in Residual Fuel Oil Storage Tanks (RP2778-11)	$60,300 3 months	Energy Systems Associates/*W. Rovesti*
SDG&E Urea Injection Demonstration, Phase 4 (RP2869-10)	$50,000 5 months	San Diego Gas & Electric Co.; Southern California Edison Co./*D. Eskinazi*
Applicability of Reburning to Cyclone-Fired Boilers (RP2916-6)	$1,151,800 30 months	Combustion Engineering, Inc./*A. Kokkinos*
Low-NO_x Burner Evaluation at Four Corners Station (RP2916-14)	$294,200 8 months	Arizona Public Service Co./*A. Kokkinos*
Dam Stability Data Monitoring (RP2917-20)	$85,800 12 months	Tennessee Valley Authority/*D. Morris*
Demonstration Unit for Cleanup of Organic Residues From Contaminated Soils: Process Development Services (RP2991-6)	$78,000 5 months	Mill Creek Co./*C. Kulik*
Engineering and Economic Evaluation of CO_2 Removal From Fossil Fuel–Fired Plants (RP2999-10)	$148,300 8 months	Fluor Daniel/*G. Booras*
Testing and Analytical Services for Selective Catalytic Reduction Pilot Plants (RP3004-4)	$763,600 30 months	Radian Corp./*E. Cichanowicz*
Carbonate Fuel Cell Demonstration (RP3059-3)	$980,000 40 months	Pacific Gas and Electric Co./*R. Goldstein*
FGD Reaction Tank/Crystallizer Development (RP3070-22)	$115,000 13 months	Radian Corp./*R. Moser*
Wilsonville Selective Agglomeration Project (RP3118-1)	$1,000,000 47 months	Southern Company Services, Inc./*H. Lebowitz*
Using On-Line Coal Analysis to Determine Western Coal Slagging/Fouling Potential: Technical Assessment (RP3123-2)	$68,000 7 months	Bechtel Group, Inc./*D. O'Connor*
Ahlstrom Pressurized Fluidized-Bed Combustion and Asahi Ahlstrom Component Test Facility Pilot Plant (RP3161-1)	$750,000 35 months	Pyropower Corp./*S. Drenker*
Improved SO_x Removal and Sorbent Utilization in Fluidized-Bed Combustion Plants (RP3197-5)	$93,300 5 months	BCR National Laboratory/*C. Siebenthal*
Strategic Management of Compliance Decisions (RP3199-1)	$194,700 8 months	Temple, Barker & Sloane, Inc./*J. Platt*
Central Appalachian Coal Industry Profile (RP3199-2)	$65,000 6 months	Resource Data International, Inc./*J. Platt*
Nuclear Power		
Technical Support and Validation of EPRI-Developed NDE Products (RP1570-32)	$95,600 9 months	J. A. Jones Applied Research Co./*S. Liu*
BWR Attachment Weld Mock-Up (RP1570-33)	$100,800 8 months	J. A. Jones Applied Research Co./*S. Liu*
Radwaste Decision Support System Feasibility Study (RP2414-36)	$84,000 7 months	Vance & Associates/*C. Hornibrook*
Fiber Optics in Radiation Environments (RP2614-69)	$126,100 21 months	Ohio State University/*J. Weiss*
Analysis of NUREG-1150 (RP2637-17)	$103,700 10 months	Stone & Webster Engineering Corp./*F. Rahn*
Stress Corrosion Cracking in Low-Strength Nickel-Base Alloys (RPC101-2)	$312,000 45 months	ABB Atom AB/*L. Nelson*
Alloy and Water Chemistry (RPC101-5)	$51,700 13 months	ABB Atom AB/*L. Nelson*

New Technical Reports

Requests for copies of reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, U.S. universities, or government agencies. Reports will be provided to nonmember U.S. utilities only upon purchase of a license, the price for which will be equal to the price of EPRI membership. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. To order one-page summaries of reports, call the EPRI Hotline, (415) 855-2411.

CUSTOMER SYSTEMS

Design Guidelines for Direct Expansion Ground Coils
CU-6828 Final Report (RP2892-4); $100
Contractor: Oak Ridge National Laboratory
EPRI Project Manager: P. Joyner

Power Electronics and Controls Program: Projects and Products, 1978–1989
CU-6854 Special Report; $100
EPRI Project Manager: B. Cox

Uncertainty in Forecasting
CU-6855 Final Report (RP2919-2); $100
Contractor: Barakat & Chamberlin, Inc.
EPRI Project Managers: P. Cleary, R. Squitieri

ELECTRICAL SYSTEMS

Field Evaluation of 69-kV Outdoor Polysil® Insulators
EL-6763 Final Report (RP1281-6); $25
Contractor: Pennsylvania Power & Light Co.
EPRI Project Manager: J. Hall

Advanced Cable Fault Locator
EL-6765 Final Report (RP2895-1); $32.50
Contractor: Purdue University
EPRI Project Manager: H. Ng

Decomposition of Linear Programs Using Concurrent Processing on Multicomputers
EL-6769 Final Report (RP1999-11); $32.50
Contractor: University of Tennessee
EPRI Project Manager: D. Maratukulam

Bulk Transmission System Loss Analysis, Vols. 1 and 2
EL-6814 Final Report (RP2716-1); Vol. 1, $47.50; Vol. 2, $32.50
Contractor: Scientific Systems, Inc.
EPRI Project Manager: D. Maratukulam

ENVIRONMENT

Environmental Performance Assessment of Coal Ash Use Sites: Little Canada Structural Ash Fill
EN-6532 Final Report (RP2796-1); $40
Contractor: Radian Corp.
EPRI Project Manager: I. Murarka

An Alternative Hypothesis for Association Between Distribution Wiring Configurations and Cancer: Planning Phase
EN-6863 Interim Report (RP2966-2); $25
Contractors: Environmental Research Information, Inc.; Enertech Consultants
EPRI Project Manager: S. Sussman

GENERATION AND STORAGE

Material and Cleaning Options for Cyclic Reheat Systems
GS-6738 Final Report (RP1652-2); $32.50
Contractors: Battelle; United Engineers & Constructors, Inc.
EPRI Project Manager: P. Radcliffe

Gas Turbine Effects on Integrated Gasification–Combined-Cycle Power Plant Operations
GS/ER-6770 Final Report (RP8000-5); $32.50
Contractor: Stanford University
EPRI Project Manager: M. Gluckman

Variable Pressure Operation: An Assessment
GS-6772 Interim Report (RP1403-16); $40
Contractor: Burns and Roe, Inc.
EPRI Project Manager: J. Bartz

Shell Coal Gasification Project: Gasification of SUFCo Coal at SCGP-1
GS-6824 Interim Report (RP2695-1); $25
Contractor: Shell Development Co.
EPRI Project Manager: N. Stewart

Fourteenth Annual EPRI Conference on Fuel Science
GS-6827 Proceedings; $325
EPRI Project Manager: H. Lebowitz

Synthetic Lightweight Aggregate From Cool Water Slag: Bench-Scale Confirmation Tests
GS-6833 Final Report (RP1654-38); $25
Contractor: Praxis Engineers, Inc.
EPRI Project Managers: S. Alpert, N. Hertz

Evaluation of Dry Sodium Sorbent Utilization in Combustion Gas SO_x/NO_x Reduction
GS-6850 Final Report (RP1682-2); $32.50
Contractor: KVB, Inc.
EPRI Project Manager: B. Toole-O'Neil

Development of Seal Legs for Atmospheric Fluidized-Bed Combustion (AFBC) Applications
GS-6858 Final Report (RP2303-1); $25
Contractor: Bechtel Group, Inc.
EPRI Project Manager: T. Boyd

Case Study Evaluation of PCB Fires
GS-6870 Final Report (RP1263-20); $32.50
Contractor: IT Corp.
EPRI Project Managers: M. McLearn, R. Komai

NUCLEAR POWER

Workshop on the Role of Sulfur Species on the Secondary-Side Degradation of Alloy 600 and Related Alloys
NP-6710-M Proceedings; $25
EPRI Project Managers: C. Shoemaker, P. Paine

Guide to Optimized Replacement of Equipment Seals
NP-6731 Final Report (RP2927-1); $32.50
Contractor: Wyle Laboratories
EPRI Project Manager: G. Sliter

Electrochemical Potential Measurements Under Simulated BWR Chemistry Conditions
NP-6732 Interim Report (RP2295-3); $32.50
Contractor: GE Nuclear Energy
EPRI Project Manager: H. Ocken

Decomposition of Hydrogen Peroxide at Elevated Temperatures
NP-6733 Interim Report (RP2295-3); $32.50
Contractor: GE Nuclear Energy
EPRI Project Manager: H. Ocken

BWR Water Chemistry Impurity Studies
NP-6773-M Final Report (RP2293-1); $25
Contractor: ABB Atom AB
EPRI Project Manager: D. Cubicciotti

Considerations for the Consolidation of BWR Fuel
NP-6783 Final Report (RP3100-1); $32.50
Contractor: Northeast Technology Corp.
EPRI Project Manager: R. Lambert

BWR Radiation-Field Assessment: 1986–1988
NP-6787 Interim Report (RP2494-1); $32.50
Contractor: General Electric Co.
EPRI Project Manager: H. Ocken

Lifetime of PWR Control Materials: Evaluation of Data From Duke Power's Oconee Nuclear Station
NP-6835-D Final Report (RP1628-3); $5000
Contractor: The S. M. Stoller Corp.
EPRI Project Manager: O. Ozer

UTILITY PLANNING

Utility Fuel Oil Market Trends: Outlook for Residual and Distillate Fuel Oil
P-6823 Final Report (RP2369-61); $40
Contractor: Pace Consultants, Inc.
EPRI Project Manager: H. Mueller

Research and Development in the 1980s: An Overview
OCSP-6894 Final Report; $25
Contractor: Dennis Briskin
EPRI Project Manager: S. Feher

CALENDAR

For additional information on the meetings listed below, please contact the person indicated.

DECEMBER

3–5
Symposium: Macrofouling
Orlando, Florida
Contact: Norris Hirota, (415) 855-2084

4–6
Fossil Fuel Plant Cycling
Washington, D.C.
Contact: Maureen Barbeau, (415) 855-2127

4–6
Workshop: Underground Cable Water Treeing
Phoenix, Arizona
Contact: Bruce Bernstein, (202) 872-9222

5–7
Workshop: Applications of Chaos
San Francisco, California
Contact: Jong Kim, (415) 855-2671

5–7
Workshop: Terry Turbine Controls
Orlando, Florida
Contact: Bob Kannor, (415) 855-2018

11
Robotics for Vaults
Chicago, Illinois
Contact: Roy Nakata, (415) 855-2301

11–12
Diesel Generator Diagnostics
Eddystone, Pennsylvania
Contact: Sam Haddad, (415) 855-2172

12–14
Workshop: Fossil Fuel Plant Control and Automation
Phoenix, Arizona
Contact: Murthy Divakaruni, (415) 855-2409

JANUARY 1991

22–25
9th International Coal Ash Utilization Symposium
Orlando, Florida
Contact: Dean Golden, (415) 855-2516

23–25
Coal Handling Systems: State of the Future
Pensacola, Florida
Contact: Barbara Fyock, (412) 479-6015

28
Waste Tires as a Utility Fuel
San Jose, California
Contact: Lori Adams, (415) 855-8763

FEBRUARY

6–8
Symposium: New Equipment and Services for Foodservice Customers
New Orleans, Louisiana
Contact: Susan Bisetti, (415) 855-7919

MARCH

5–6
Instrument Air Systems
Baltimore, Maryland
Contact: Lori Adams, (415) 855-8763

6–8
Value-Based Transmission
Washington, D.C.
Contact: Pam Turner, (415) 855-2010

25–28
1991 Symposium on Stationary NO_x Control
Washington, D.C.
Contact: Maureen Barbeau, (415) 855-2127

APRIL

2–5
Improved Coal-Fired Power Plants
San Francisco, California
Contact: James Valverde, (415) 855-7998

16–18
Radiation Field Control
Palo Alto, California
Contact: Lori Adams, (415) 855-8763

MAY

1–3
Biological Processing of Coal
San Diego, California
Contact: Susan Bisetti, (415) 855-7919

7–9
Conference: Heat Rate Improvement
Scottsdale, Arizona
Contact: Pam Turner, (415) 855-2010

JUNE

4–6
Conference: Cycle Chemistry
Baltimore, Maryland
Contact: Maureen Barbeau, (415) 855-2127

18–20
Workshop: Condensate Polishing
Scottsdale, Arizona
Contact: Lori Adams, (415) 855-8763

26–28
Power Plant Pumps
Tampa, Florida
Contact: Susan Bisetti, (415) 855-7919

JULY

16–18
Steam Turbine Generator Life Assessment and Maintenance
Charlotte, North Carolina
Contact: Tom McCloskey, (415) 855-2655

30–August 1
5th National Demand-Side Management Conference
Boston, Massachusetts
Contact: Bill LeBlanc, (415) 855-2887

SEPTEMBER

9–11
Expert System Applications
Boston, Massachusetts
Contact: Susan Bisetti, (415) 855-7919

18–20
International Conference: Use of Coal Ash and Other Coal Combustion By-Products
Shanghai, China
Contact: Dean Golden, (415) 855-2516

OCTOBER

8–11
PCB Seminar
Baltimore, Maryland
Contact: Maureen Barbeau, (415) 855-2127

15–18
Meeting Customer Needs With Heat Pumps
Dallas, Texas
Contact: Pam Turner, (415) 855-2010

21
Coal Gasification
San Francisco, California
Contact: Lori Adams, (415) 855-8763

28–November 1
Particulate Control
Williamsburg, Virginia
Contact: Susan Bisetti, (415) 855-7919

NOVEMBER

3–5
Managing Hazardous Air Pollutants
Washington, D.C.
Contact: Lori Adams, (415) 855-8763

Authors and Articles


Rauch


Carey


Burke


Byron


Edmonds


McCloskey


Dooley

Exploring the Options for Magnetic Field Management (page 4) was written by Taylor Moore, *Journal* senior feature writer, with assistance from several members of EPRI's Customer Systems, Electrical Systems, and Environment divisions. Principal technical guidance came from the Electrical Systems Division.

Greg Rauch, a project manager in the Electrical Systems Division's Distribution Program, oversees most of EPRI's engineering research on magnetic fields and power quality. He joined EPRI as a technology transfer administrator in 1988 after 11 years with General Electric, where he held several international and domestic positions in product applications, marketing, and sales. ■

Nuclear Plants: Life After 40 (page 20) was also written by Taylor Moore, with principal assistance from three members of the Nuclear Power Division's Plant Life Extension Program.

John Carey, senior program manager, joined the Institute as a project manager in 1976 and became a program manager in 1979. He managed research in safety and relief valve testing, degraded core cooling, and hydrogen combustion before assuming responsibilities in the life extension area. Before coming to EPRI, Carey was a mechanical engineer with the Argonne National Laboratory.

Richard Burke, project manager, came to EPRI in 1984 as a loaned employee from Vermont Yankee Nuclear Power Corp., where he had worked since 1969, ultimately as department manager for operations support. At EPRI, Burke has managed research projects in the areas of plant availability and operations and maintenance; he joined the Nuclear Power Division permanent staff in 1987.

Jeff Byron, project manager, joined EPRI in 1985 and first managed research on fossil plant life extension in what is now the Generation and Storage Division. He joined the Nuclear Power Division in 1987. Before coming to EPRI, Byron held engineering positions with Aptech Engineering Services, Acurex, and the nuclear division at General Electric. ■

Solutions for Solid-Particle Erosion (page 30) was written by Leslie Lamarre, science writer, with information from three staff members of EPRI's Generation and Storage Division.

Jim Edmonds, manager of the Rotating Machinery Program, has been with the Institute since 1978. He was with the Electrical Systems Division for 10 years and then spent a year on loan to the National Science Foundation before assuming his present responsibilities. Edmonds came to EPRI from the Department of Energy and has also worked for American Electric Power Service.

Tom McCloskey has been a technical adviser with EPRI's Generation and Storage Division since 1980, specializing in research to improve the performance and reliability of steam turbines. He formerly worked for 11 years in the steam turbine division of Westinghouse Electric, first as a design engineer and later as a project engineer in the management of large turbine steam bypass systems.

Barry Dooley, a technical adviser with special expertise in boilers and auxiliaries, joined the Institute in 1984. Previously he spent nine years with Ontario Hydro, where he became manager of the chemistry and metallurgy department. For three years earlier, Dooley was with the materials division of the Central Electricity Research Laboratories in England. ■

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