Risk and the Human Environment

ELECTRIC POWER RESEARCH INSTITUTE

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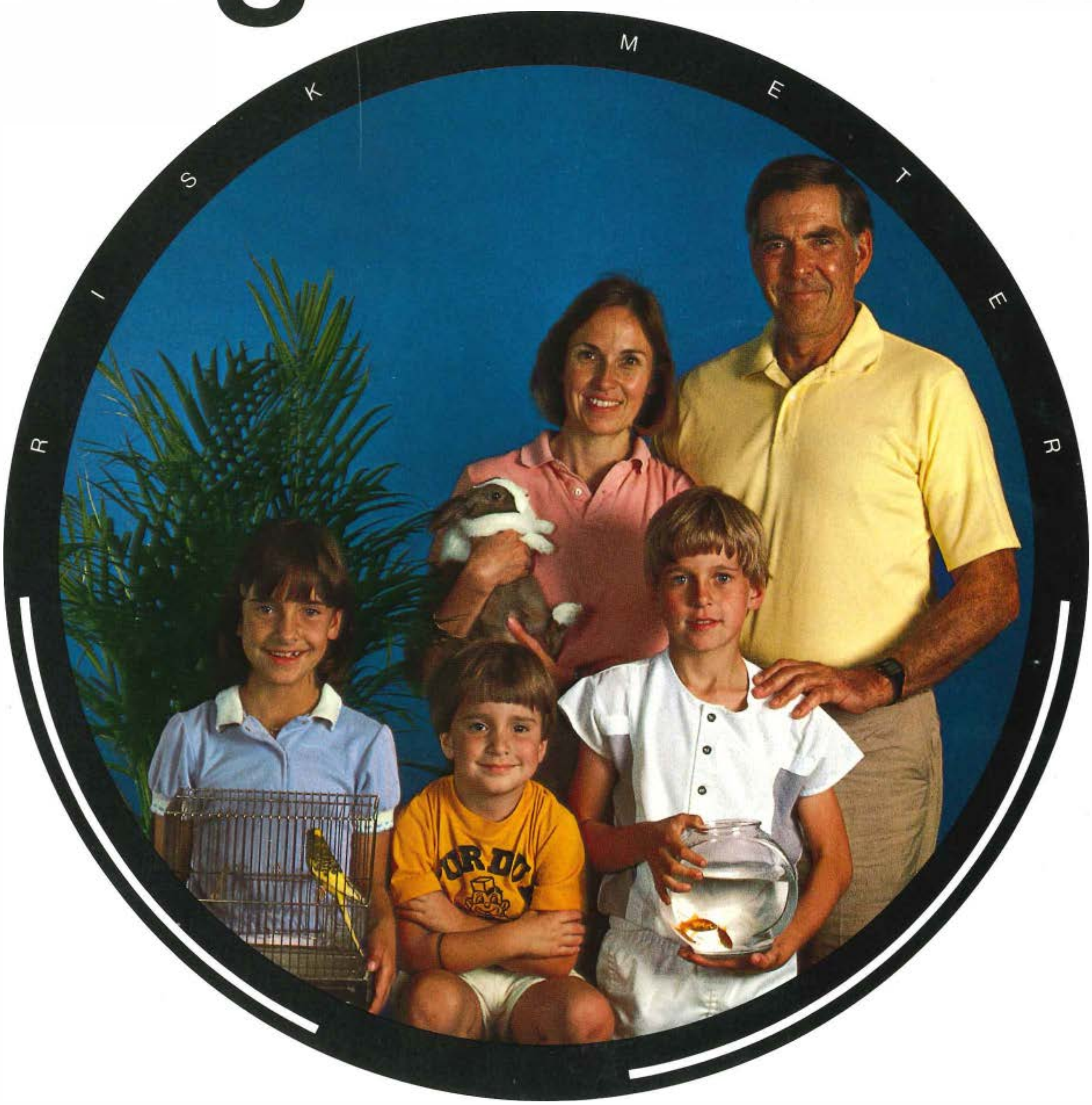

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Cover: For man and his environment, risk is an everyday experience—a combination of natural and man-made hazards that subtly influence the way he lives. New assessment and decision-making tools are helping clarify how large these environmental risks actually are and how we can best use society's resources to manage them.

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Dealing Rationally With Risk

Decisions related to personal risk pervade our daily lives, yet for most of recorded history people have not had formal methods for analyzing risks. Intuitively, people understand that a risk involves both the unwanted consequence of some action and the uncertainty that this consequence will actually occur. For many decisions involving common risks—such as deciding whether to drive, given the obvious dangers—intuitive analysis may be adequate. However, when decisions must be made about very complex risks—for example, those involving food additives, medical care, or environmental pollution—the unwanted consequences can affect many people, and these people may have little or no direct control over the decisions made. For such decisions intuition may no longer be adequate. Because our society is now faced with many such decisions, formal analytic tools for assessing and managing risks are becoming increasingly desirable.

When decisions about protecting the environment from pollution first became prominent in the 1950s and 1960s, the choices seemed clear. It was a time when the undesirable side effects of unbridled industrial growth were rapidly becoming apparent. Unreclaimed mining operations had created desolate landscapes. Uncontrolled discharges had transformed some pristine streams into sewers. And a variety of chemical pollutants (such as phosphates) created enough stress in fragile ecosystems to result in the extinction of most life in some lakes. Something had to be done.

As society rallied to reverse these trends, numerous environmental protection acts were passed and an encouraging change in public mores occurred. The ultimate goal was to make the effects of a highly industrialized society virtually unfelt and unseen in what was thought to be a fragile world of natural systems. It soon became apparent, however, that the effects of industrial activity could not be completely eliminated; the concept of zero risk was simply impossible to implement. Therefore, in the next stage of environmental protection, a goal of using the "best available control technology" was adopted in key legislation or regulations.

Now the limits of this approach are also becoming evident, for what is the best available technology for one engineer can always be improved by another. Our financial resources are limited and cannot be committed indefinitely to an endless pursuit of diminishing returns from improving emission controls. Priorities need to be set concerning which risks should be controlled first, and the costs of various approaches must be compared with the benefits expected.

Such complex risk decisions require new analytic tools that are both objective and quantitative. One set of these tools involves risk *assessment*—the calculation of the degree and likelihood of exposure and concomitant hazard. It is the task of risk assessment to provide the best estimate of risk that can be derived from available scientific data and to display fully the uncertainties and unquantifiable effects. The other set of analytic methods involves risk *management*—the process of using the information provided by risk assessment to determine the desirability of various strategies for mitigating risk. An important advantage of risk assessment and risk management tools is that they can provide a common framework for opposing sides to use in discussing complex issues.

Much work remains to be done in developing better analytic methods of both types. Assessments of risk may vary widely because of great uncertainties in available scientific data, and new ways need to be found to reduce the uncertainties and more easily take them into account. Similarly, risk management calculations are often hampered by the difficulty of quantifying many highly emotional issues: what is the value of a clean stream or an undegraded vista or the avoidance of human illness? Opposing sides in an environmental debate often differ substantially in their perceptions of such values and in their willingness to accept a risk in the face of uncertainty.

These difficulties have left some members of the environmental community suspicious of quantitative methods for analyzing risk. They worry that such analyses may be used as an excuse for ignoring their concerns, which they believe are ultimately unquantifiable. One way to alleviate these fears is to separate risk assessment from risk management, so that scientific judgments are insulated from issues involving social values.

As the lead article discusses, EPRI is actively developing a variety of new analytic methods for risk assessment and management. The article also describes some applications of these tools to important problems facing the electric utility industry. The final task of using these methods to address policy decisions has been left to individual utilities, trade associations, regulatory agencies, and various other interest groups.

The decisions being affected by quantitative risk analysis are important; they relate to matters of great public concern, to potential harm that could have substantial costs, and to control decisions that could require billions of dollars a year in additional costs. Despite the difficulties that remain, the analytic tools now being developed are fundamental to making this decision process more rational and efficient. Improved decisions will assure utilities and their customers that they will have to bear only the needed and desirable costs of producing electricity in an environmentally compatible manner.

René Malès, Vice President
Energy Analysis and Environment Division

Authors and Articles

Progress in pollution abatement becomes more orderly as we distinguish clearly between risk assessment and risk management. In **Measuring and Managing Environmental Risk** (page 6), science writer John Douglas reviews several examples where consistent methodologies have been developed for separately evaluating and dealing with environmental risks incurred in the production of electric power. The article draws on the expertise of three members of EPRI's Energy Analysis and Environment Division.

Ronald Wyzga, technical manager for risk analysis since 1982, came to the Institute in March 1975. Originally a project manager for health effects studies, he turned to economic analyses of environmental risks in 1978. Before 1975 Wyzga was with the Organization for Economic Cooperation and Development in Paris for four years; still earlier he was an instructor at the Harvard University School of Public Health, where he earned an ScD in biostatistics in 1971. Wyzga also has a BA in mathematics from Harvard College and an MS in statistics from Florida State University.

Richard Richels, technical manager for decision methods and analysis, has been with EPRI since August 1976. Until January 1982 he was a project manager for energy and environmental systems modeling studies. Richels was formerly a consultant to The Rand Corp. and the National Science Foundation. A physics graduate of the College of William and Mary, Richels earned an MS in industrial engineering before turning to operations research, in which he holds an MS and a PhD from Harvard University.

Stephen Peck, technical director of the Environmental and Economic Integration Staff since it was formed in 1982, joined the Institute in October 1976 and became manager of the Systems Program in 1979. From 1971 to 1976 he was an assistant professor of economics at the University of California at Berkeley. A Cambridge University graduate, Peck earned an MSc at London University and an MBA and a PhD in economics at the University of Chicago.

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Wrecking balls and redevelopment schemes are familiar eventualities for most outmoded industrial facilities. But special expertise is needed when a nuclear power plant comes to the end of its useful life. **Decommissioning Nuclear Power Plants** (page 14) reviews the alternatives for plant decommissioning. Taylor Moore, senior feature writer for the *Journal*, developed the article with major assistance from two program managers in EPRI's Nuclear Power Division.

Adrian Roberts, senior manager of the Fuels and Materials Program, came to the Nuclear Power Division in September 1974 and managed research in core materials until 1979. He then spent a year at Cornell University as a visiting professor before taking his current position. Roberts was formerly with the materials science division of Argonne National Laboratory. He holds BS, MS, and PhD degrees in metallurgy from Manchester University (England).

Robert Shaw, senior manager of the Low-Level Waste and Coolant Technology Program, joined EPRI in June 1975; he became a manager of radiation control projects in 1977 and a program manager two years later. For 11 years before 1975, Shaw was on the chemical engineering faculty at Clarkson College of Technology in Potsdam, New York. He has a BS in engineering science from Pennsylvania State University, an MS from Stanford University, and a PhD in nuclear science and engineering from Cornell University.

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If half your budget went to heat the house, you would pay close attention to the condition of your furnace, shop around for the best price on fuel, and get smart about the factors likely to influence price the next time around. Electric utilities are in just such a circumstance today, and **New Flexibility in Fuel Planning** (page 22) reports on a recent EPRI-sponsored seminar on utility fuels. Science writer Francis Kovalcik put the article together, assisted by two research managers from EPRI's Energy Analysis and Environment Division.

Howard Mueller, a project manager in the Energy Resources Program since September 1982, is principally concerned with analytic methods for fuel supply planning. For five years before coming to EPRI, he directed the state of Maryland's power plant site selection activities and its program of electricity demand forecasting, energy conservation, and alternative energy analysis. Between 1975 and 1977, following graduate work in economics at the University of Cincinnati, he taught there and was a consultant in utility economics. Mueller earned his BS in chemistry at Dartmouth College.

Jeremy Platt, also of the Energy Resources Program, has been with EPRI since July 1974. His focus is the geology of fuel resources and the estimation of reserve quantities, but he also manages projects that deal with fuel markets, supplies, and forecasts. Platt majored in geological sciences at Harvard University and earned an MS in geology at Stanford University.

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As it becomes clear that the circumstances influencing utility plans also influence each other, and because these circumstances have begun to change more rapidly, corporate planners face a greater number of alternative outcomes and courses of action than they can calculate, much less evaluate. Comprehensive—or integrated—modeling is providing a way to manage the problem, as described in **UPM: Modeling at the Corporate Level** (page 30). To introduce this product of EPRI-sponsored research and review its early application, science writer Stephen Tracy turned to EPRI's Lewis Rubin.

Rubin, a project manager in the area of decision methods and analysis, is concerned mainly with research in corporate and R&D planning. Before coming to EPRI in December 1978, Rubin was with the Federal Energy Administration for four years, where he was responsible for analyzing and modeling proposed legislation. He holds BA and MA degrees in economics from Lehigh University and Brown University.


Shaw


Wyzga

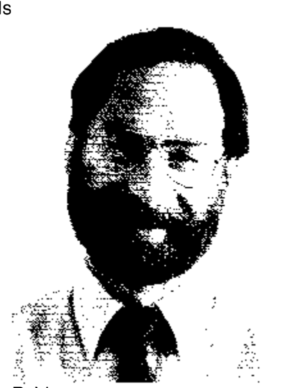

Roberts


Peck

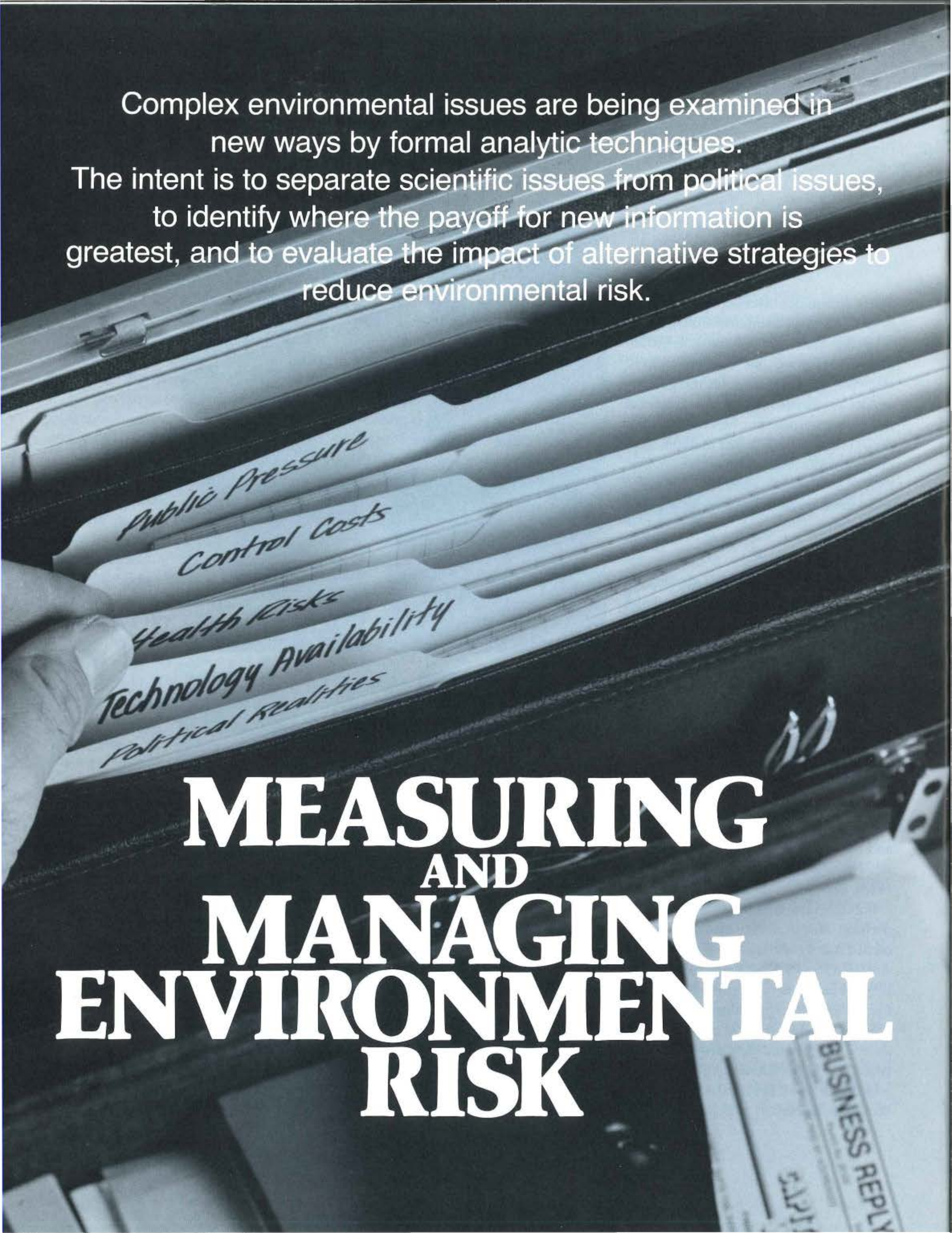

Platt


Richels


Mueller


Rubin

Complex environmental issues are being examined in new ways by formal analytic techniques. The intent is to separate scientific issues from political issues, to identify where the payoff for new information is greatest, and to evaluate the impact of alternative strategies to reduce environmental risk.



MEASURING AND MANAGING ENVIRONMENTAL RISK

In a 1983 speech to the National Academy of Sciences (NAS), William Ruckelshaus, then administrator of the U. S. Environmental Protection Agency (EPA), reflected on how scientific understanding of risk had changed since he had first been with the agency 10 years earlier. At that time, he said, "I believed it would become apparent to all that we could virtually eliminate the risks we call pollution if we wanted to spend enough money." And when the enormous cost of such control became apparent, he said, "I further believed we would begin to examine the risks very carefully and structure a system that forced us to balance our desire to eliminate pollution against the costs of its control."

Such a system didn't materialize, and on returning to EPA, Ruckelshaus found that "we must now deal with a class of pollutants for which a safe level is difficult, if not impossible, to establish. . . . We must assume that life now takes place in a mine field of risks from hundreds, perhaps thousands of substances. No more can we tell the public: you are home free with an adequate margin of safety."

This disturbing revelation has required profound changes in the way risks are assessed and managed. The philosophy behind many early regulatory standards was to limit pollution to levels at which no adverse health effects were detected. For agents that cause some health risks, such as cancer and genetic damage, however, there is no proven threshold of safety. Even if the number of detected cancer cases that result from public exposure to a suspected carcinogen does not increase, current research indicates that some risk may still exist. As a result of this discovery, an intense national debate is being waged over how to establish standards for pollutants for which "safe" levels do not exist but which cannot be completely eliminated from the environment without very large expenditures. A key factor in helping settle this debate will almost certainly be the development of new, more-sophisticated methods of analyzing risks.

Two different types of methodologies are required for such analysis: those that assess risks and those that support decision making in the management of risk. Separating these two tasks has become increasingly important in avoiding confusing scientific conclusions about the nature of a risk, on the one hand, and political and economic concerns over how it should be handled, on the other. Generally speaking, risk assessment attempts to determine the seriousness of some health hazard. The steps include identification of a potentially hazardous substance, determination of its dose-response relationship to various health problems, estimation of likely public exposure to the substance, and characterization of the resulting health risk in quantitative terms. On the basis of this assessment, risk management techniques can then be used to aid in setting priorities for action and to analyze alternative control strategies. These techniques generally involve calculations either to determine the cost-effectiveness of a particular strategy or to weigh the relative costs, benefits, and risks of various control options.

Such analytic methods can be useful to both government agencies and the industries they regulate. Quantitative models of risk provide an improved framework for regulatory decisions by requiring all parties to state their assumptions explicitly and to recognize each of the values (such as good health, for example, or the need for a reliable power supply) that must be taken into account. These methods can also be used to communicate the realities of risk to an increasingly agitated and skeptical public, by showing the relative importance of various risks and what trade-offs would be needed to control them.

Quantitative analysis can help both policy makers and the public deal with the uncertainties that are an inherent part of risk. Often in the face of uncertainty, established practice has been simply to pass even stricter regulations based on worst-case assumptions. Too often, these assumptions have been unrealistic and have thus distorted the economics of health protection. Better models of risk may help reduce the need for overly conservative regulations and thus provide a more realistic basis for spending limited funds.

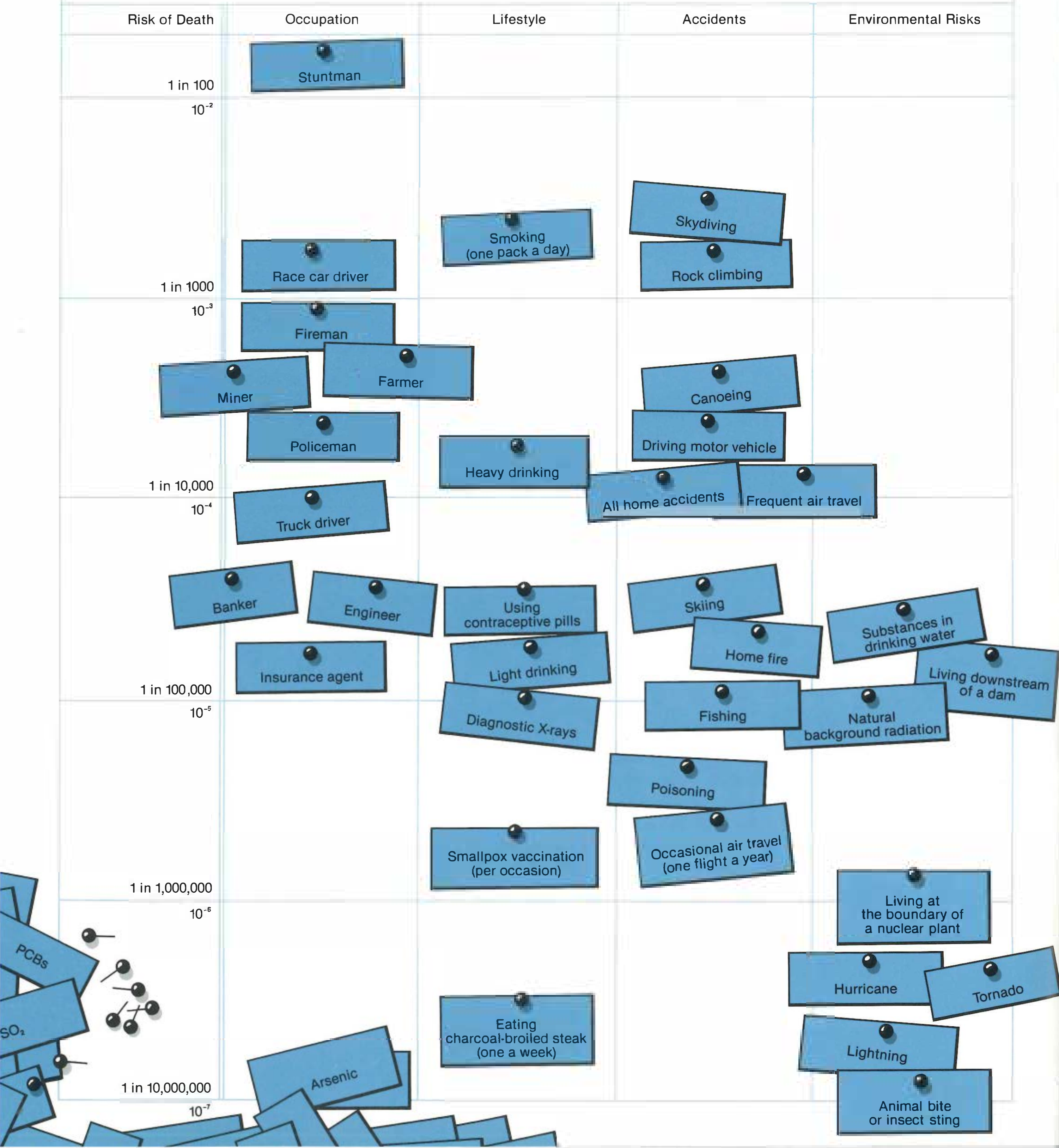
Although the need for new methods of quantitative risk analysis is now widely recognized, substantial problems remain before this approach can reach its full potential. Critical gaps in available scientific information often make risk assessment difficult, and emotional issues sometimes obscure the value of risk management studies. "Even where there is scientific information, the inherent uncertainties lead to skepticism by the public who expect scientists to know 'the answer,'" says René Malès, vice president for the Energy Analysis and Environment Division. As federal regulators turn increasing attention to these challenges, EPRI is helping prepare a variety of state-of-the-art risk assessment and risk management tools for the utility industry. "EPRI has particularly committed itself," Malès says, "to develop tools capable of reflecting the uncertainties in scientific information."

Separating assessment and management

In his speech to the NAS, Ruckelshaus was responding, in part, to an academy report recommending that risk assessment and risk management functions be separated within agencies like EPA and that uniform guidelines be established for all government agencies concerning how scientific risk data were to be interpreted. This report, issued in 1983, served to focus attention on the importance of quantitative risk analysis in the development of regulatory standards throughout the federal govern-

Putting Risk in Perspective

Nearly all human activities involve some risk, as shown in this chart of the estimated risk of dying in a single year as a result of various activities. The degree of risk ranges widely, both in fact and in perception; most activities with a risk above 1 in 1000 (10^{-3}) are both voluntary and unacceptable to the majority of the population. Occupational, lifestyle, accident, and some environmental risks are known with reasonable accuracy, since they are based on actuarial data; however, the environmental risks presented by many specific substances, such as PCBs, SO_2, and arsenic, require further study through risk assessment techniques before they can be positioned on the chart with confidence.



ment and to highlight some sources of dissatisfaction with the way those standards were currently being set.

"By separating risk assessment and risk management, we were trying to separate the judgments of science—made by scientists through the process of peer review—from regulatory judgments, which include not only science but also a lot of issues having to do with economics and politics," says D. Warner North, a principal of Decision Focus, Inc., and a member of the NAS committee that wrote the report on risk analysis. And if regulatory agencies adopt a uniform set of guidelines on making inferences from available scientific information, he says, they can avoid "bringing up chemicals one by one and having the same debates fought over how to deal with the uncertainties and how to interpret the data for that chemical."

One of the federal agencies that has implemented the academy recommendations is EPA, where two recent decisions illustrate the importance of risk assessment and risk management in the regulatory process. Several years ago, EPA issued rules that, it was hoped, would eventually phase out the use of leaded gasoline while preventing severe economic dislocations in the lead and petroleum industries or causing unacceptably high incidence of adverse health effects. Further research indicated, however, that the amount of lead in blood is directly related to the amount of lead in gasoline and revealed more information about health risks for children with elevated lead levels in their blood. These scientific data, together with the discovery that about 12% of all cars equipped with catalytic converters to control exhaust emissions were being misfueled with leaded gasoline, led EPA to reassess the risks posed by the continued availability of such gasoline.

Having assessed the presence of lead to be a "major public health problem," the agency conducted an extensive risk management analysis that showed the benefits from reducing lead in gasoline were at least three times as large as the costs. As a result, EPA set new standards that will cut the amount of lead in gasoline by 90% in 1986. At about the same time, the agency used similar procedures to conclude that some sources of benzene, a known carcinogen, were not worth controlling further because the costs far outweighed the benefits.

Important as quantitative risk assessment and risk management were in bringing EPA to these two decisions, many cases are not so clear-cut and the agency sometimes faces severe limitations in using these methodologies. "The major limitation on risk assessment is the quality of the science," says Milton Russell, assistant administrator of EPA for policy and program evaluation. "Often we do not have enough information in a case to know precisely what the impacts of a substance are, or there may be uncertainties and difficulties in quantifying the risk. To achieve at least consistency, if not certainty, what we have done is publish risk assessment guidelines so that everybody in the agency is looking at the same chemicals in the same way and making the decision based on the same scientific protocol."

Risk management decisions are also made more difficult because of incomplete information, according to Russell, particularly when the costs and benefits of certain pollution abatement measures are uncertain or the ancillary impacts of a proposed regulation remain unknown. Requirements of a law that force certain actions to be taken without leaving room for administrative discretion can also cause difficulties. "Statutory rigidities," says Russell, "may preclude us from going after the worst things first or may require us to take particular actions without giving us any choice in terms of risk management decisions." Such inflexibility in the laws governing environmental protection can even create new risks, he says: "It's a simple fact that everything's got to go somewhere. If you act on legislation to clean up the air by scrubbing smokestacks, let's say, you have to dispose of the material gathered; but putting it in a landfill may create more risk in terms of groundwater contamination than if you let it go into the air in the first place."

The need for better tools

Because of such difficulties, substantial effort is being made nationwide in both the public and private sectors to improve risk assessment and risk management. Part of this effort is focused on closing critical gaps in scientific knowledge. The need to determine human health risks by extrapolating from animal data has long been an area of particular concern. During the debate over health risks from saccharin, for example, the estimated number of potential cancer cases resulting from typical human exposure ranged from 0.001 cases per million people exposed to 5200 cases per million, depending on which animal data were used and how extrapolations were made. To help improve such extrapolation procedures, investigators are now studying how different animals metabolize toxic materials and how the resulting health risks vary according to size and species.

Another major task is to develop better analytic tools that can provide adequate models of risk, even in the face of scientific and economic uncertainties. Such tools can substantially improve the quality of dialogue on sensitive issues by providing to industry, regulators, and the public a common framework for decision making. Well-crafted models of risk assessment and management can be used not only to establish priorities for regulatory action, but also to help industries determine the best course of action to accommodate new standards, indicate flaws in current legislation, and improve communication of choices to the public.

For several years EPRI's Energy Analysis and Environment Division has been developing analytic tools in both the risk assessment and risk management areas for the electric power industry. Utilities are now using these methodologies in such diverse applications as determining the potential health effects of trace arsenic emissions from power plants to calculating the costs and benefits of various strategies for dealing with acidic deposition. In the future an even broader range of analytic methods may be made available, providing utilities with fundamentally new means of decision support.

Assessing utility-related risks

One of the most important recent developments in environmental protection is the rising concern over the emission of substances that are known to be toxic but that are released in such small quantities that their regulation is still widely debated. In the electric utility industry, this concern has focused on such toxic power plant emissions as trace metals and polycyclic organic compounds that either have been identified as potential carcinogens in humans or have caused cancer in laboratory animals when administered in high doses. To help power plant owners assess the risk posed by these substances, EPRI has developed new computer codes that model emissions to the air and water and estimate the resulting health risks.

The air emission risk assessment model (AERAM) estimates excess human cancer risk, if any, that can result from inhaling hazardous air pollutants from coal-fired power plants. The computer code embodying this model consists of four modules, which address the emission of various pollutants, their atmospheric transport, population exposure patterns, and the resulting health risks. These modules can take into account a variety of important factors, including coal characteristics, power plant burner parameters, the extent of emission controls, local meteorologic data, and population densities. Because the way cancer develops is still not well understood, three different methods are used to extrapolate dose-response relationships from existing animal data. Each method is based on a specific theory of carcinogenesis, and results from the three methods can be used to estimate upper and lower bounds of cancer risk for that method. The computer code was developed for EPRI by Arthur D. Little, Inc.

AERAM received its first utility application last year when Northeast Utilities used the model to evaluate any potential health risks from emissions of arsenic and benzo-a-pyrene (BaP) from its Mount Tom power plant in Holyoke, Massachusetts. This 155-MW(e) plant burns bituminous coal from Pennsylvania and removes most ash by wet sluicing and electrostatic precipitation. Remaining emissions are released through a 113-meter stack.

The model was used to calculate the excess lifetime risk that cases of cancer would occur in the affected community from exposure to minute quantities of arsenic and BaP emitted from the plant. Depending on which data extrapolation method was used, the lifetime risk that even one additional cancer case would occur in the community varied from three chances in a billion to three chances in a thousand for arsenic, with the risk from BaP being still smaller. Translated into per capita terms, the largest lifetime risk to any particular individual of contracting cancer as a result of exposure to either of the two toxic materials emitted by the plant was about two chances in a hundred million.

"EPRI's risk assessment models can help utilities in a variety of ways," says Ronald Wyzga, technical manager of the environmental risk analysis program. "In particular, they can sometimes enable utilities to obtain variances from regulations that are based on unrealistic worst-case scenarios by providing a means to demonstrate that incremental health risks resulting from some emission are negligible. We are now actively involved in technology transfer efforts so that more utilities can take advantage of our codes in the toxic substances area. We are also trying to further improve the predictive power of such risk assessments through the use of recently developed methods that model biological functions."

The ability of a risk assessment model to predict the effects of human exposure to toxic substances under realistic conditions is inherently limited by how well extrapolations can be made from the very different conditions that exist in a laboratory. Typically during an experiment, small animals are exposed to very high doses of the substance in question and test results must then be adjusted to account for differences between species and the low dose levels received by humans. This is usually done by extrapolating on a weight basis from the most sensitive animal species.

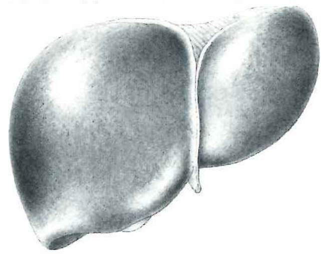
To improve the validity of such extrapolations, advanced biological modeling techniques have been developed, based on comparison of how animals and humans metabolize various substances. The primary aim of these techniques, developed as part of a young field of scientific specialization called pharmacokinetics, is to quantify the relationship between the delivered dose of a substance initially ingested or inhaled by a human or animal and the effective dose that actually reaches sensitive organs of the body. Although some toxins (including many insecticides) affect certain species in unique ways, pharmacokinetic studies have shown that determining effective doses and responses for an appropriate experimental animal can better enable scientists to predict a reliable dose-response relationship for humans exposed to the same substance. Pharmacokinetics can also indicate which species of animal is most appropriate to use as an experimental model for extrapolation purposes.

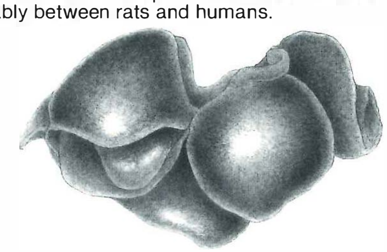
Pharmacokinetics

Assessing the health risk of toxic substances often requires extrapolating the results of animal experiments to humans. Such extrapolations can be improved by studying how various animals, including humans, biologically handle specific chemicals—a field of science called pharmacokinetics. From these studies a quantitative relationship can be established between the administered dose of a toxic material and the effective dose that reaches sensitive organs, such as the liver, kidneys, lungs, and spleen. By providing comparisons of how these organs function in different species, pharmacokinetics enables scientists to determine which laboratory animals would be best for use in testing a specific toxic substance and how a human dose-response relationship could best be derived from the animal data.

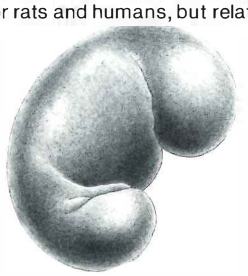
HUMAN | RAT

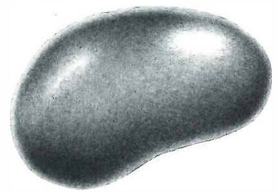
Liver: The primary organ for detoxifying hazardous materials. The specific metabolic reactions involved in such detoxification can differ considerably between rats and humans.



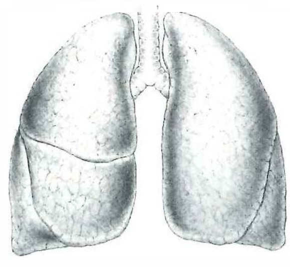


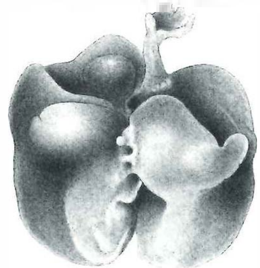
Kidneys: Remove and excrete harmful materials from the bloodstream. The basis of action is similar for rats and humans, but relative rates of excretion are quite different.



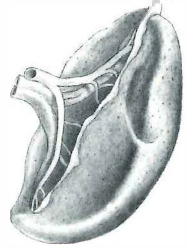


Lungs: Primarily involved in providing oxygen to the blood, but also perform some detoxification. Rats breathe much faster than humans, and their lungs have a somewhat different structure.





Spleen: Stores red blood cells and acts as source of immunological defense. Response to toxic materials can differ substantially; rats, for example, naturally incorporate arsenic into their red blood cells in a way very different than humans.



EPRI is now pioneering the use of such techniques for utility issues through a two-year project being conducted at the University of Arizona. The immediate objective of the project is to assess the possible human health risks associated with exposure to two proposed alternatives to polychlorinated biphenyls (PCBs) as insulating and dielectric fluids in electrical equipment. The two alternative chemicals, phenylxylylethane and isopropylbiphenyl, currently lack basic toxicological and pharmacokinetic information, and the specific aim of the ongoing project is to provide the data needed for assessing their risk to humans. Beyond this immediate goal, however, the work is expected to provide procedures that can be used in designing more effective risk assessment studies of other toxic materials encountered in the utility environment.

Utility risk management

Today's risk management needs, particularly those related to the sort of very complex issues likely to be encountered in the electric power industry, go far beyond the narrow concept of limited cost-benefit analysis. As originally formulated, such analysis was intended to help decision makers choose among specific management alternatives available at a particular time, assuming that all pertinent values could be directly expressed in monetary terms. In risk management, however, broader and more flexible decision frameworks are needed that incorporate a variety of values and can allow for strategies that may change over time as many uncertainties are resolved by research.

"EPRI is now able to give utilities risk management tools that can help them face a variety of complex issues," says Richard Richels, technical manager of the decision methods and analysis program. "These tools are designed to help decision makers balance the benefits and the costs of alternative strategies for reducing risk, based on the best available information at the time. They also help focus attention on those aspects of a problem that are really driving a decision. In this way, they provide invaluable insights as to where additional research will have the highest payoff."

One of the most complicated utility industry issues now being addressed through risk management techniques is that of acidic deposition. Under EPRI sponsorship, a risk management framework has been developed that can be used to compare various strategies for dealing with acidic deposition. In particular, it can be used to weigh the advantages of immediately tightening controls on power plant emissions against those of waiting to learn the results of current research before deciding whether to control emissions further or to use other methods for mitigating damage in selected sensitive areas. Incorporated into a computer code called ADEPT (for acid deposition decision tree), this framework can be used to investigate the impact of acidic deposition control and mitigation decisions in different geographic areas and to reveal the various trade-offs that may be made to reach agreement. Developed for EPRI by Decision Focus, ADEPT was first used to analyze the problem on a regional basis but now has been adapted for use at the state level.

Earlier this year, ADEPT was used to analyze risk management alternatives for acidic deposition in Wisconsin. The study was sponsored by the Wisconsin Utilities Acid Deposition Task Force and incorporated judgments about the likelihood and extent of ecological damage obtained from a panel of experts in several fields. According to this panel, acidification of up to 15,000 acres of lakes—about 2% of the state's lake area—was judged to have a probability of 10%. Productivity declines affecting up to 10% of Wisconsin's forested land area was considered to have a probability on the order of 1% within the next 50 years.

Risk assessment techniques are used to identify potential health hazards and to determine their seriousness. Such techniques usually involve taking laboratory data to establish a dose-response relationship for an individual exposed to some toxic material, as well as estimating the extent of public exposure. Often this task is made more difficult by gaps in scientific knowledge about the effects of a particular chemical or about the mechanisms by which diseases such as cancer develop. EPRI has prepared several analytic tools that can provide improved risk assessments for the electric utility industry despite remaining uncertainties. AERAM, for example, estimates the health risks associated with air pollutants produced by coal-fired power plants, and WTRISK provides a similar analysis for water pollutants.

Risk management techniques are used to examine potential health problems already identified by risk assessment techniques in order to determine the best course of action for preventing them. EPRI is now developing a portfolio of quantitative risk management tools that can analyze alternative strategies in a variety of utility-related applications. Such analysis involves the construction of a decision tree that explicitly lays out all assumptions, values, and uncertainties, then calculates the costs associated with each course of action. The ADEPT model, for example, determines the likely impact of various strategies for coping with acidic deposition, while TRIM analyzes different options for phasing out PCB transformers.

Given these judgments, the ADEPT analysis revealed that few environmental impacts would occur as the result of a strategy of waiting for further scientific investigation of the problem, compared with imposing more stringent emission controls now. The expected impact on Wisconsin lake resources from waiting 10 years before imposing a 50% reduction in sulfur dioxide emissions regionally on sources affecting Wisconsin is a 10% probability of temporary acidification of 400 to 600 acres of lakes, an area of less than one square mile. The expected loss in forest damage from the delay in imposing regional sulfur dioxide control is a 1% probability of a productivity decline affecting several hundred thousand of Wisconsin's 15 million acres of forest lands. The ecological benefits of requiring more stringent regional control now rather than waiting would be an expected saving, averaged over the next 50 years, of 50 acres of lakes and 900 acres of forest.

The ADEPT model (which is also discussed in the Energy Analysis and Environment Division's R&D Status Report, p. 59) provides a framework that allows a variety of interested groups to discuss a mutual problem involving major scientific uncertainties and regional implications. A very different sort of risk management tool is needed to help utilities choose among the limited options for solving much more specific and localized problems, such as phasing out transformers containing PCBs.

A computer code especially designed to analyze the costs and benefits of various phaseout strategies, TRIM (for transformer/capacitor risk management), was developed for EPRI by Decision Focus. Last year the Utility Solid Waste Activities Group (USWAG) and the Edison Electric Institute used it to respond to proposed EPA regulations by analyzing four specific policy alternatives: normal replacement schedule, accelerated phaseout (all PCB transformers in or adjacent to buildings removed by 1995), highly accelerated phaseout (all removed by 1990), and a program to reduce chances of transformer incidents involving fires, plus special labeling and notification to protect fire and emergency-response workers from exposure to PCBs.

Results of the TRIM analysis, using conservative assumptions based on the best available industry and EPA data for equipment inventories, costs, and incident occurrence, showed that over a 25-year period less than one case of serious health effects could be expected from following the normal replacement schedule. (Stated formally, the expected incidence of health effects was 0.325.) The risk reduction program (the fourth option) would cut the expected incidence of health effects by about half—to 0.150—and a highly accelerated phaseout would reduce this figure again by about one-third. On the basis of these estimates, the cost of avoiding a single case of serious health effects would be more than $800 million under the risk reduction program and more than $2 billion under a program of accelerated phaseout.

"Without a doubt, we have been able to improve the quality of dialogue with regulators by using such risk management techniques," says John A. Taylor, manager of water quality at Virginia Power and chairman of USWAG. "Risk tools help you talk about concrete items rather than abstract ideas. We can attempt to quantify more than we have been able to do in the past. Some of these analyses clearly show we have been spending millions of dollars trying to prevent something small from happening, and I believe that money could be put to better use elsewhere."

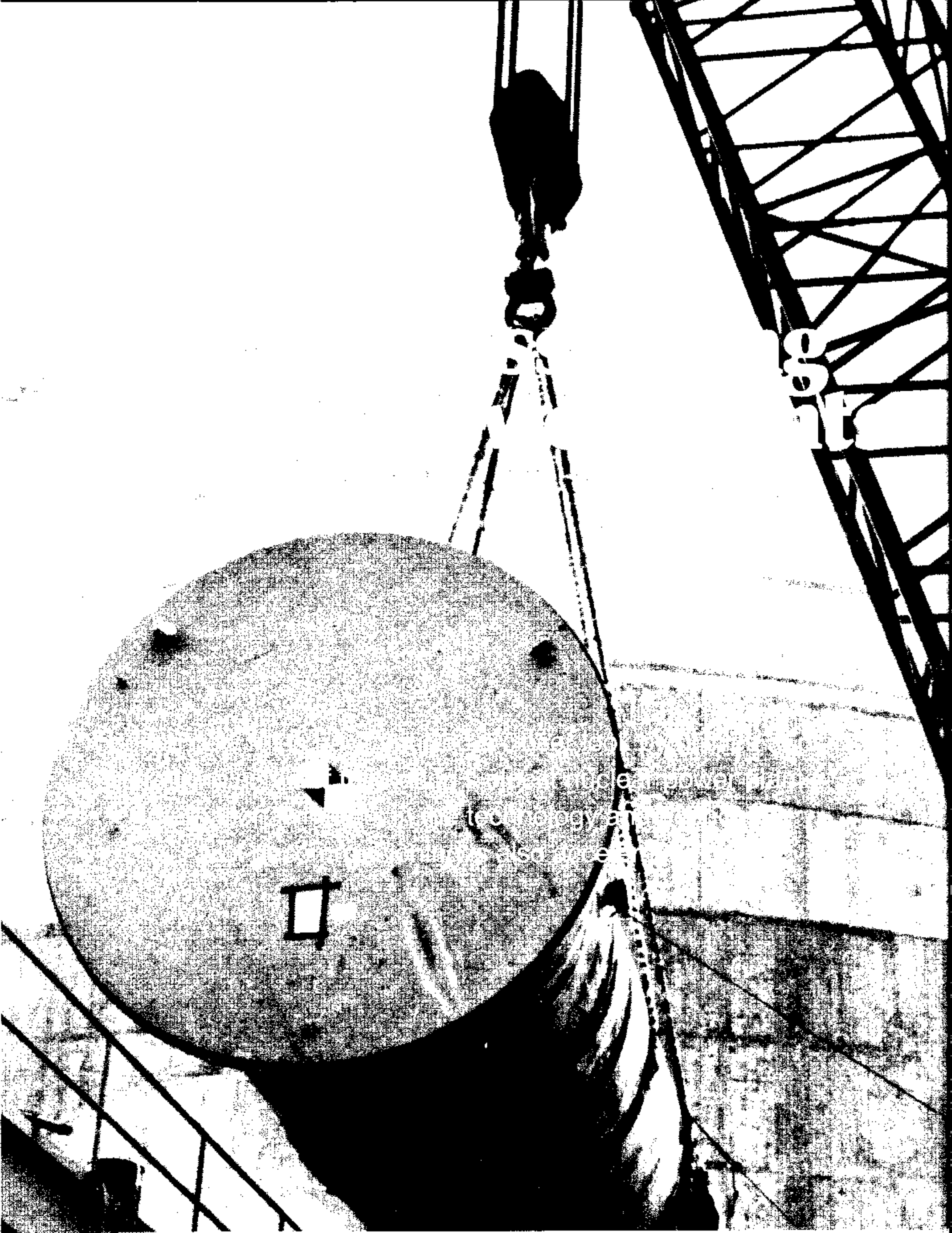
The future of risk analysis

The use of both risk assessment and risk management tools is still a relatively recent development, particularly in the electric power industry. As their practical application by utilities has increased, however, so has the importance of EPRI's efforts to provide new analytic methods for dealing with increasingly complex decisions. In some cases these methods can provide industry representatives with more effective ways of estimating the impact of proposed regulations and offering alternative solutions to environmental problems. In others, individual utilities can use EPRI codes to determine the environmental impact of their own plants or to decide which emission strategies are likely to prove most cost-effective.

"Looking toward the future, I believe we can help utilities develop more specific and reliable estimates of risk, and we can also help them cope with many of the uncertainties inherent in present estimates," says Stephen Peck, technical director of the Environmental and Economic Integration Staff. "Current efforts to incorporate the methods of pharmacokinetics, to improve dose-response estimates, and to adapt laboratory results to real-world situations should reduce the extent of uncertainties in future risk assessments," he says. Meanwhile, research on how people judge values related to risk and on why personal perceptions of risk often differ so widely from objective calculations of risk probabilities may reveal better ways for utilities to communicate with regulators and the public about risk management.

Out of this effort, Peck says, "I hope we can develop methods that will help utility management anticipate problems before they arise and then provide an improved framework for reaching more widely acceptable solutions." ■

This article was written by John Douglas, science writer. Technical background information was provided by Ronald Wyzga, Richard Richels, and Stephen Peck, Energy Analysis and Environment Division.



Some of the nation's nuclear power plants that have been generating power for many years could become candidates for decommissioning after the turn of this century. Operating licenses for seven reactors are scheduled to expire by 2005, but by 2010 the number is estimated to reach 65. Although efforts are under way to establish the technical bases for extending the life of some plants beyond their design life, retirement of the first generation of nuclear plants will eventually occur. With this in mind, the utility industry, the Nuclear Regulatory Commission (NRC), EPRI, and other groups have begun laying the groundwork to get the job done.

Decommissioning—the measures taken at the end of a plant's operating life to ensure protection of the public from residual radioactivity or other hazards—has been a sore point with critics of nuclear power. It is claimed that estimates of the cost and scope of engineering activities are uncertain because of a lack of significant experience in decommissioning large reactors. Critics also contend that current regulations do not guarantee utilities will have the necessary funds when the time to decommission a plant arrives. NRC is addressing the latter point in proposed revisions to regulations that spell out requirements for planning, financing, and carrying out decommissioning at commercial power plants and other nuclear facilities.

As for the claim that not enough experience with decommissioning exists to have confidence the job can be done within predicted costs, "That just isn't true," says Adrian Roberts, a senior program manager in EPRI's Nuclear Power Division. "Admittedly, utilities haven't yet done some of the things they will be doing in decommissioning, but most of the operations involved *have* been done for other reasons at one time or another. The technology for decommissioning nuclear plants is available now."

Interest accelerating

Consideration of decommissioning normally begins around the time a plant's operating license expires, generally 35–40 years from the date of issuance of a construction permit. There is no simple tally of the number of plants and the timetable under which they will come up for possible decommissioning. As is widely acknowledged throughout the utility and nuclear industries, the 40-year nominal license term specified by the 1954 Atomic Energy Act, which set the stage for regulation of commercial nuclear power, was not based on reactor engineering considerations; some plants may be capable, with modification, of reliable, safe operation well beyond 40 years. Many utilities along with EPRI are now exploring the potential for renovating nuclear plants and obtaining extended or renewed operating licenses, if NRC agrees to such an approach.

Other factors may make a plant subject to decommissioning earlier than normal: some plants have become uneconomic because of increased repair and maintenance requirements; in some cases, retrofits required to bring a plant up to current safety standards make continued operation unjustifiably expensive; or a major accident, such as that at Three Mile Island Unit 2, can lead to consideration of closure and decommissioning for economic reasons.

Thus, although no plant today is near the end of its service life, a number of plants built during the demonstration phase of the nuclear power program are closed and facing some form of eventual decommissioning. These include Shippingport, the trailblazing LWR built by Admiral Hyman Rickover's Naval Reactors Group and Duquesne Light Co., which was the first to generate power on a utility grid; Commonwealth Edison Co.'s Dresden-1 in Illinois, Pacific Gas and Electric Co.'s Humboldt Bay reactor on the northern California coast, and Consolidated Edison Co. of New York's Indian Point-1, all among the first generation of commercial LWRs built in the 1960s; and TMI-2.

Several European nuclear plants are also slated for decommissioning: Gundremmingen-A, Niederaichbach, and Lingen in West Germany; the Windscale prototype gas-cooled reactor in the United Kingdom; and Italy's Garigliano reactor. In addition, Canada's Gentilly-1 and Japan's Power Demonstration Reactor are to be decommissioned.

International interest in decommissioning has been accelerating for the last six years, reflected in four major recent symposia: in Vienna in 1978, Seattle in 1982, Luxembourg in 1984, and Bethesda, Maryland, this July. These gatherings have focused mainly on commercial power plant decommissioning, although many studies and applicable regulations also cover test reactors, nuclear fuel processing plants, and other facilities.

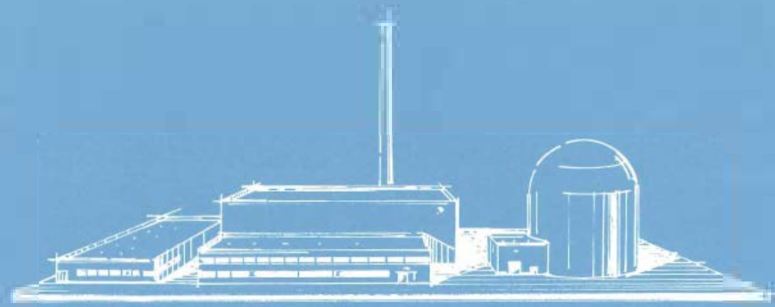
NRC has given renewed impetus to decommissioning in its proposed revisions to the technical and financial criteria contained in the federal regulations governing commercial nuclear power. The proposed amendments, expected to be issued as final rules next year, are the product of a seven-year process at NRC that has included development of a generic environmental impact statement on decommissioning and a series of NRC-funded studies on the technology, safety, and costs of decommissioning various kinds of nuclear facilities.

NRC defines decommissioning as the safe removal of a nuclear facility from service and a reduction of the residual radioactivity to a level permitting release of the property to unrestricted use and termination of the plant license. The commission's proposed (or extant) decommissioning rules, however, do not specify what levels of residual radioactivity will be permissible; these are to be defined under a separate rule making now under way in conjunction with EPA.

Many people commonly assume that decommissioning is intended to restore a plant site to its original "green field" condition, but this is unlikely to be the case in most instances, particularly those in which an aging, early generation reactor shares its site and water source with

Degrees of Decommissioning

Proposed new NRC rules define three alternative approaches to decommissioning nuclear reactors. Utilities will be required to specify which approach will be taken a year before a plant's license expires or within two years after operations cease, whichever comes first.



DECON—Decontamination and dismantlement

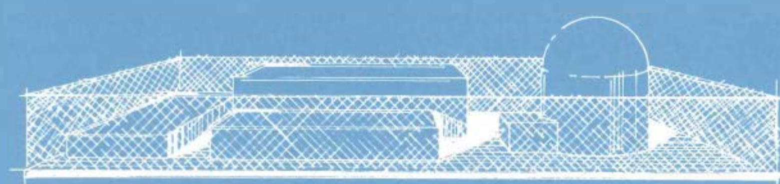
- Plant fully decontaminated
- Fuel assemblies removed
- Nonradioactive parts salvaged
- Primary system, pressure vessel, and containment dismantled
- License terminated; property released for unrestricted use

SAFSTOR—Safe storage and deferred dismantlement

- Reactor core defueled
- Limited decontamination
- Containment structure and equipment securely maintained for 30–50 years
- Site remains partially restricted

ENTOMB—Entombment

- Limited decontamination of work areas
- Radioactive materials confined in containment
- Containment doors and penetrations sealed with concrete
- Plant security maintained up to 100 years under amended license



larger, younger operating plants. "Our view is, once a nuclear site, always a nuclear site," says EPRI's Roberts. "There's so much money already invested in the site, the licensing, and peripherals such as water supply, switchyard, security force, and environmental analysis, that we don't see much value in green fielding. In such cases, we believe that safe storage, or mothballing, of a facility—or even entombment—may be a utility's preference unless it has only a fixed-term lease for the site land. This decision may be followed later by construction of a new plant on the site, as demand for electricity increases and new generating capacity is required."

Degrees of decommissioning

NRC's proposed new rules reflect this need for flexibility by identifying three distinct approaches to decommissioning. The alternatives constitute degrees of decommissioning, ranging from immediate decontamination and full dismantlement (DECON), to safe storage and deferred dismantlement (SAFSTOR)—also known as mothballing—and entombment (ENTOMB). Utilities must indicate to NRC which method will be pursued within two years after a plant ceases operation or one year before its operating license expires, whichever comes first.

In the DECON approach, the plant is fully decontaminated; fuel assemblies and other radioactive materials are removed; certain nonradioactive components are salvaged; and the reactor vessel, other primary system elements, and containment structure are systematically dismantled, packaged as radioactive or nonradioactive waste, and shipped for disposal. When the job is completed, the license is terminated, and the property is released for unrestricted use.

Under the SAFSTOR alternative to immediate dismantlement, the reactor is defueled and other radioactive materials and contaminated areas are decontaminated or secured. Structures and equipment to be dismantled later are securely maintained to prevent public exposure to residual radioactivity. The facility is in a passive state during safe storage, and the plant site remains restricted under an amended license.

Entombment involves decontamination of limited areas—those that are to be accessible in the future. Remaining radioactive materials are confined within a monolithic structure—all doors and containment penetrations are sealed with concrete. This practice is intended to ensure structural integrity and protection of the public until radioactive decay reduces the levels of entombed radioactivity enough to permit unrestricted release of the site. The plant must also be guarded around the clock.

"Of the three alternatives, it is generally accepted that DECON and SAFSTOR raise fewer open issues," says Roberts. "Each has its advantages. DECON is probably cheapest over the long run, because it qualifies the site for unrestricted use earliest and doesn't require long-term plant security." NRC estimates the total occupational radiation dose for DECON of a large LWR at about 400 man-rems per year (1200–1900 man-rems over 4–5 years), a level generally less than current annual doses at operating reactors.

But SAFSTOR for 30–50 years significantly reduces both the occupational dose to decommissioning workers and the total amount of radioactive waste requiring disposal. Cobalt-60, with a half-life of 5.3 years, is the radionuclide of most concern in decontamination; 30 years of safe storage would reduce the cobalt-60 to less than one-fiftieth (0.02%) of its level at shutdown.

PG&E's 65-MW (e) Humboldt Bay reactor in California is now in SAFSTOR, with eventual dismantlement slated following a cooling-off period of up to 30 years for radioactive decay. The northern California utility estimates that SAFSTOR, 30 years of custodial care, and eventual dismantlement will cost about $70 million (in 1984 dollars).

The overall impact of either DECON or SAFSTOR is generally similar, according to Roberts, with the lower occupational dose and waste associated with SAFSTOR compensating for the added cost of controlling the site for a long period. Proposed NRC rules suggest that the benefits of SAFSTOR accrue within 30–50 years; they also indicate that plants should not be placed in SAFSTOR for more than 100 years, considered the maximum reasonable time for relying on institutional controls to protect the public.

Radionuclides bound in the neutron-activated steel of the reactor vessel and its internals include niobium-94 (a half-life of 20,000 years) and nickel-59 (a half-life of 80,000 years). They decay too slowly for entombment to be a viable decommissioning option at a nonoperating site unless the reactor vessel and internals are removed. If they are removed, utilities would still have to characterize in detail the remaining radioactivity to be entombed in the reactor and to demonstrate that it would decay to unrestricted release levels within about 100 years—a task, notes NRC, that would be difficult.

Experience with decommissioning

Nearly all reactors decommissioned to date have been rated at less than 200 MW in thermal output. A typical large reactor, with an electrical rating of 1000 MW, would have a thermal rating of about 3000 MW at 32% thermal efficiency. Of 23 decommissioned reactors, most of which were early test prototypes, 14 were rated higher than 10 MW (th). Of these 14, 10 were power production plants, whereas 4 were principally test facilities. About 50 research (nongenerating) reactors have also been decommissioned, typically by dismantlement.

"We've looked at the decommissioning record of these plants and found that the level of work done at each of them varied considerably," says Roberts. Most of the units are in some form of safe storage, including Northern States Power Co.'s 54-MW (e) Pathfinder at Sioux Falls, South Dakota, Philadelphia Electric Co.'s 40-MW (e) Peach Bottom-1, and Detroit Edison Co.'s 60-MW (e) Fermi-1 breeder reactor.

Entombed plants include the Piqua (Ohio) Municipal Power System reactor that powered 11 MW (e) of generating capacity; the Puerto Rico Municipal Power Authority's 16-MW (e) Bonus reactor; and the 75-MW (e) sodium-cooled Hallam reactor in Nebraska.

Full decontamination and dismantlement has been performed at only one LWR: the 22-MW (e) Elk River unit in Minnesota, which belonged (then) to the Rural Cooperative Power Association. The three-year, $6.15 million job was completed in 1974 with the demolition and removal of the 8-foot-thick (2.4-m) concrete containment building walls.

Two current decommissioning projects are proceeding at a fair pace and are considered illustrative of the spectrum of activities associated with decommissioning, says Roberts. These are Gundremmingen-A in West Germany and Shippingport in the United States. Although the work at these sites will not be indicative in every way of the task of decommissioning larger reactors, the plants are serving as laboratories, in many important respects, for the refinement of decommissioning and decontamination techniques, tools, and worker dose-reduction programs.

Gundremmingen-A is being mothballed, or put into safe storage, for eventual dismantlement; its turbine building is being fully decontaminated for unrestricted use. Two 1000-MW (e) BWRs are now operating at the same site—a principal factor in the choice of the SAFSTOR approach for the original, 250-MW (e) unit. Gundremmingen-A's reactor pressure vessel, biological shield, steel containment, and concrete containment and auxiliary building walls have been left intact. Spent fuel and other radioactive materials are being stored within the containment structure. About 1000 tons of steel will be removed from the reactor building as nonradioactive scrap.

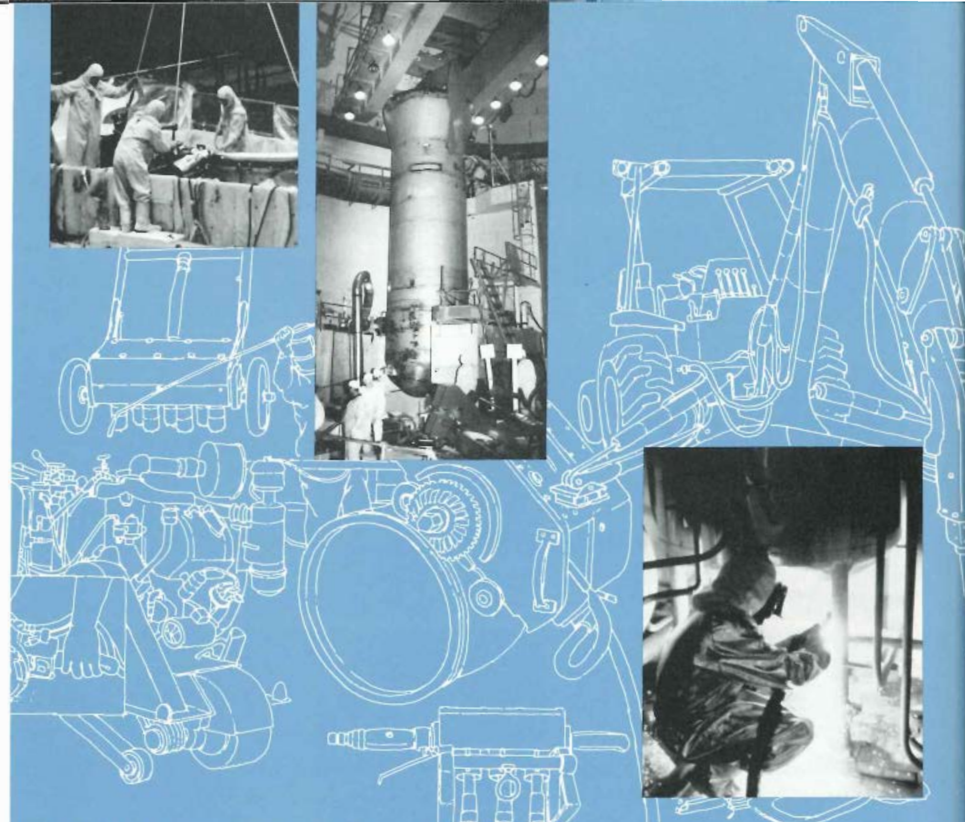
Because BWRs produce some radioactivity in the turbine generator system, the turbine building is the major focus of decontamination work at Gundremmingen-A. To date about 100 tons of material have been dismantled using conventional demolition technology, according to Roberts, including plasma arc torches and metal saws for cutting and low-pressure warm water spray for decontamination. About half that material was electropolished for final decontamination and released as scrap.

One problem encountered at Gundremmingen-A is caused by toxic materials rather than radioactivity: 35 tons of slightly contaminated asbestos insulation are now stored in drums. Disposal of such contaminated, and otherwise toxic, waste is an issue to be addressed for large-scale decommissioning.

"Decontamination of metal for release as scrap is straightforward at Gundremmingen," says Roberts. "Research has shown that the optimum combination of decontamination techniques is ultrasonic cleaning followed by electropolishing. In some cases, prebrushing with steel brushes has saved electropolishing time by a factor of 2. Two electropolishing baths are operating on a production-line basis, and installation of a melting furnace is planned for reducing waste volume," he adds.

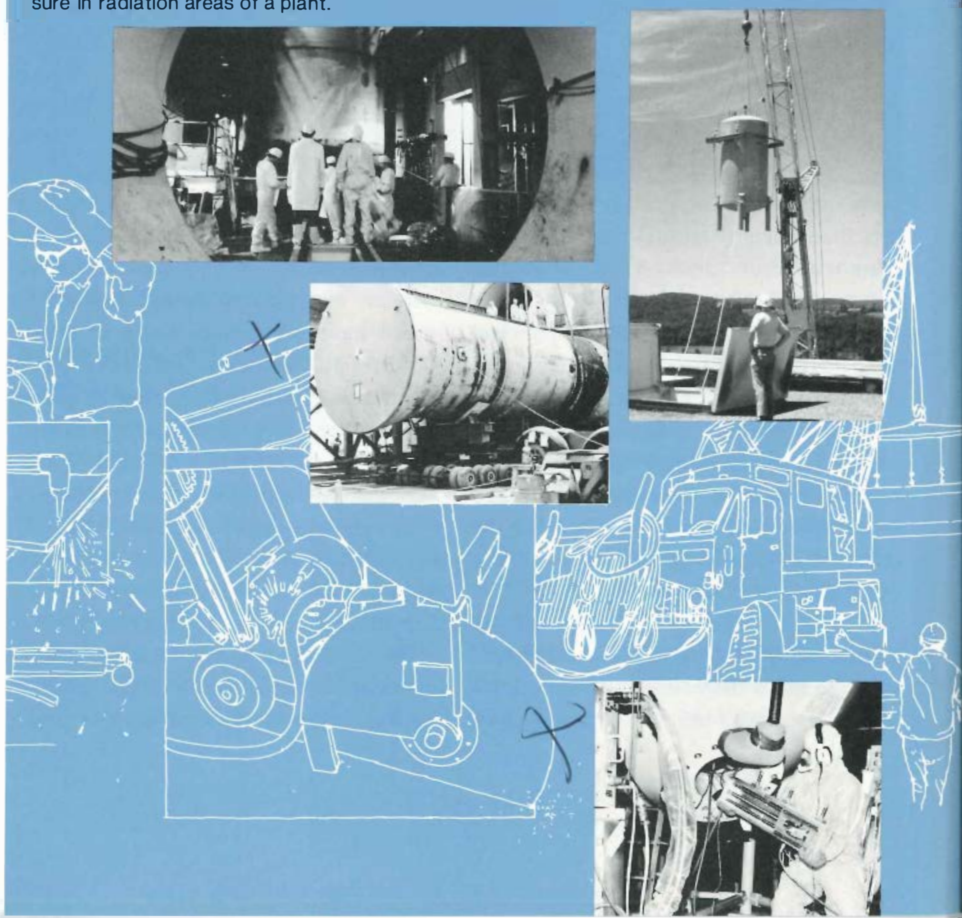
Tearing down Shippingport

After a quarter-century service record, the first commercial nuclear electric generating station—the Shippingport reactor, 25 miles northwest of Pittsburgh on the Ohio River—will soon become the largest power reactor ever decommissioned in the United States. Originally built as a four-loop 60-MW (e) PWR, the Shippingport core was replaced with an experimental 72-MW (e) light-water breeder (mixed-oxide) core in 1978. Its fuel has been sent to the Idaho National



Technology for Nuclear Decommissioning

For the most part, decommissioning nuclear reactors involves methods and technology that are already common in plant operations. Conventional decontamination techniques, including water spray, scabbling, and electropolishing, are directly applicable to decommissioning. Large components—for example, steam generators and large-diameter pipe sections—have been removed from reactors and replaced; core barrels have been cut up underwater. Such conventional tools as concrete cutting saws and plasma arc cutters, along with ordinary demolition techniques, will be used in decommissioning. In addition to commercially available technology, robotic devices are being developed for remote operations that will help minimize worker exposure in radiation areas of a plant.



Engineering Laboratory for study of the extent of breeding.

The Department of Energy, which owns the Shippingport reactor, is funding the decommissioning work, managed under contract by General Electric Co. and its subcontractors. Work began this year and is to be completed, according to recent estimates, in 1990 at a cost of $98 million. Duquesne Light Co., which operated Shippingport, will retain ownership of the land and balance of plant, including the turbine generator.

Two features of the Shippingport decommissioning are especially noteworthy in that they are unlike conditions that will pertain to most large decommissioning jobs in the future: no primary system decontamination will be undertaken, and the reactor pressure vessel will be removed intact.

Because of its design and the fact that two major decontamination operations were performed during earlier, unrelated work, Shippingport may be the least radioactive of any nuclear plant to have operated for a significant time. There is virtually no contaminated concrete, and unusually low radiation levels eliminate the need for gross decontamination of the primary reactor cooling system. The plant's total inventory of radioactivity is estimated at 14,500 curies, compared with a range of from 100,000 to 4 million curies that would be expected in a large, 1200-MW (e) LWR at shutdown after 40 years' operation.

The size of the Shippingport reactor pressure vessel (400 tons with internals) will also make work easier for the decommissioning crews because it can be removed from the plant in one piece, encased in concrete, and shipped by barge as one 770-ton piece to the Hanford Reservation in Washington State for disposal as radioactive waste. Most larger reactor vessels will have to be cut into sections remotely and under water to minimize worker exposure to radiation.

Estimated occupational exposure for the entire Shippingport decommissioning is about 1000 man-rems; at peak

PROPOSED NRC DECOMMISSIONING CRITERIA AT A GLANCE

(Revisions to 10 CFR Parts 30, 40, 50, 51, 70, 72)

UNITED STATES NUCLEAR REGULATORY COMMISSION

Decommissioning alternatives

- NRC defines three alternative approaches:

  DECON: Immediate decontamination and dismantlement, permitting release of property for unrestricted use and termination of operating license.

  SAFSTOR: Partial decontamination, safe storage, and deferred dismantlement for 30–50 years; amendment of operating license to possession only.

  ENTOMB: Encasement of contaminated structures in concrete; long-term surveillance; utilities required to demonstrate that entombed radioactivity will decay to unrestricted release levels within 100 years (which makes entombment difficult and costly).

- Permissible level of residual radioactivity for release of property to unrestricted use is to be developed under a separate rulemaking.

Timing

- Decommissioning must begin shortly after permanent cessation of operations, but delay may be permitted on case-by-case basis if compensating benefit (reduction of occupational radiation exposure or radioactive waste volume) is demonstrated.

Planning

- Applications for new licenses must provide financial assurance (funding methods, including cost estimates) for decommissioning; such information for existing licenses must be submitted within two years after revised rules take effect.
- Updated cost estimates and financial plans must be submitted five years before projected end of operations.
- Detailed decommissioning plans must be submitted two years after operations cease or one year before expiration of operating license, whichever comes first.
- Plans must demonstrate that decommissioning can be accomplished safely; must address and justify the proposed decommissioning approach; and must specify plans for and availability of radioactive waste disposal, procedures for quality assurance for occupational and public safety, and procedures for final radiation survey.

Financial assurance

- Licensees must provide "reasonable assurance that adequate funds are available to ensure that decommissioning can be accomplished in a safe manner and that lack of funds does not result in delays that may cause potential health and safety problems. The licensee is responsible for completing decommissioning in a manner that protects health and safety."
- Amount of funds assured may be based on site-specific cost estimate or amount prescribed in the final regulations (proposed to be $100 million in 1984 dollars adjusted for inflation at a rate of two times the change in the U.S. consumer price index).
- The following alternative methods of providing financial assurance are acceptable:

  Prepayment of cash or other liquid assets prior to facility startup into account segregated from licensee assets and control.

  Deposit of funds at fixed intervals over life of facility into external sinking fund segregated from licensee assets and control.

  Development of internal reserves by using negative net salvage value depreciation to invest in licensee assets over facility life; bonds are later issued against the funds; can also take the form of segregated internal reserves.

  Provision of insurance and other guarantee methods (especially for premature decommissioning expenses).

Environmental review requirements

- Requirements of National Environmental Policy Act related to decommissioning are reduced; environmental impact statement (EIS) for decommissioning is replaced by requirement for less-extensive environmental assessment to supplement EIS for construction permit and operating license.
- Approval of decommissioning funding plans is categorically excluded from requirements for EIS or environmental assessment.

workload, about 250–350 people will be involved in the project. Compared with segmentation of the vessel and internals, the one-piece vessel removal is anticipated to save about $7 million, reduce personnel exposures for that task by about 100 man-rems, and shave a full year from the overall schedule.

According to John Schreiber, DOE manager of the Shippingport project, the effort will yield valuable experience and insight applicable to future decommissioning jobs regardless of the approach in handling the reactor pressure vessel. "The overall diameter of the Shippingport vessel, with its external neutron shield, is about 18 feet. That's very close to the size of vessels in larger reactors. We think that whether intact vessel removal is applicable to future jobs or not, the worker dose-management efforts and cost and scheduling controls will contribute to better planning and management in future decommissioning projects," says Schreiber.

EPRI is involved at Shippingport as an observer, looking for insights that might benefit utilities planning for the future. Explains Robert Shaw, a senior program manager in the Nuclear Power Division, "We have some concern about the extent to which Shippingport could establish precedents that would be applied to commercial decommissioning. Some of the approaches that will be taken at Shippingport, including the intact removal of the vessel, for example, may be either too expensive or technically inappropriate for commercial practice. We intend to closely monitor the Shippingport work for examples of what we think would be applicable for the utility industry, as well as those that just don't fit."

Roberts believes that the experiences at Shippingport and the nearby cleanup effort at TMI-2 will tend to bracket the industry's future needs for decommissioning technology. "Although TMI-2 entails much more extensive decontamination than will be required for a large reactor that was shut down normally, most of the tools and techniques that are being used and developed for TMI-2 will be directly applicable to routine decommissioning," he adds.

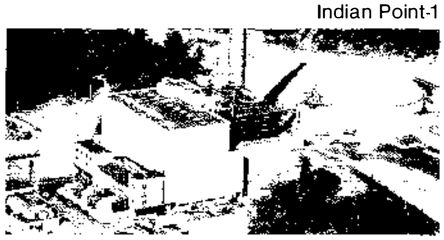
Candidates for Decommissioning

Decommissioning projects are already under way at the government-owned Shippingport reactor in Pennsylvania, which was the first reactor to generate commercial nuclear power (in 1957), and at Gundremmingen-A, a West German BWR. Shippingport is to be dismantled over the next five years, and Gundremmingen-A is being mothballed, or placed in safe storage, for later dismantlement.
Other American reactors that face some form of decommissioning in the years ahead include Pacific Gas and Electric Co.'s Humboldt Bay unit on the California coast, Commonwealth Edison Co.'s Dresden-1 plant in Illinois, and Consolidated Edison Co.'s Indian Point-1 in New York.

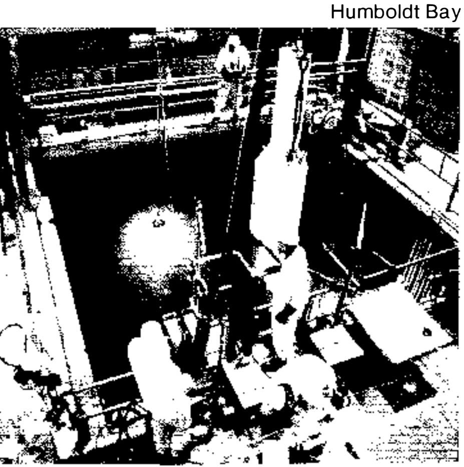
Dresden-1

Gundremmingen-A

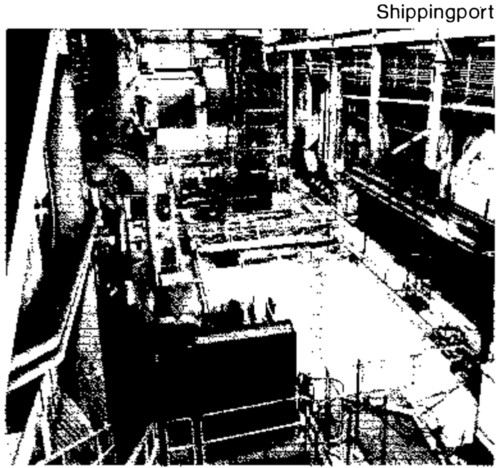
Indian Point-1



Humboldt Bay



Shippingport



Associated technology

Utilities operating nuclear plants are already familiar with most of the tools and techniques that will be used in decommissioning, experts agree. "We already have the various pieces of decommissioning technology in hand," says Roberts. "We know how to decontaminate, and there are several chemical and mechanical methods available for different types of contamination.

"We know we can remove major components from the plants because we're already doing that with steam generator replacements in PWRs and large-diameter primary system piping in BWRs. We know how to cut metal remotely, and we certainly know how to cut or blast away concrete. The only part of the decommissioning spectrum that hasn't been done is remote sectioning and removal of a reactor vessel, but we believe that can be done as well because we have remotely cut up and removed core barrels, which are nearly as large as the reactor vessels that contain them.

"In decommissioning, we're dealing with a relatively well understood sequence of events," says Roberts. "You have to decontaminate and dismantle the various structures inside the containment, knock the containment down, dispose of a certain amount as normal waste, and send the rest to high-level waste disposal. Decommissioning simply means you're dealing with large amounts of waste and other materials rather than the small amounts encountered in normal plant repair operations.

"So, the technology for decommissioning is all there. Admittedly, to keep the individual worker exposures low, within either 3 or 5 man-rems/yr, you've got to use a lot of workers over several years or use remote technology as a countermeasure," Roberts adds.

A wide variety of remote technology for sampling, measuring radioactivity, cutting metal or concrete, and decontamination by scabbling or water spray is becoming available to nuclear utilities. Some of the technology development has been sponsored by EPRI, including mobile robot systems deployed at TMI-2 to aid in the cleanup and recovery effort.

Shaw agrees with Roberts on the availability of procedures and technology for decommissioning, but points out that one aspect receiving closer attention is waste packaging and disposal. "Some of the waste that will come from decommissioning will be of a different character than you traditionally get from an operating plant. The reactor vessel and internals are radioactive from direct neutron bombardment, meaning the steel itself is radioactive and must be disposed of as nuclear waste. But it may not come under the normal classification of low-level waste. Different requirements and costs could be associated with these portions.

"We've begun a project to take a closer look at that and try to determine whether some of the work we've done in the past on the technology and cost of volume reduction and other efforts in low-level waste can be applied to decommissioning wastes," Shaw adds.

Cost estimates

The cost of decommissioning has been the subject of numerous studies by NRC, the Atomic Industrial Forum (AIF), EPRI, and other groups. Each has attempted to carefully define the steps involved in decommissioning and, on the basis of a detailed understanding of plant systems, estimate the magnitude of work and associated cost.

NRC's proposed new rules will require utilities to demonstrate that decommissioning funds will be available when needed. The regulations suggest a figure of $100 million (1984 dollars), which may be substituted with a more specific estimate for a particular plant. In comments on the proposed rules, AIF has suggested that $120 million to $170 million may be a more realistic figure.

AIF this year will issue guidelines for utilities to use in estimating the cost of decommissioning. The guidelines are designed to allow planners to include site-specific costs within a generalized framework that takes into account recent advances in decontamination and remote systems. AIF's guidelines also provide a common terminology and methodology that will help in comparing decommissioning costs among different reactor types.

EPRI has also contributed to a clearer picture of decommissioning costs. It recently contracted with Battelle to update previous generic estimates. Although actual costs will vary considerably because of many plant-specific factors, some summary generic estimates of the costs of various methods of decommissioning can be made.

Immediate decontamination and dismantlement of a reference 1100-MW PWR is estimated to cost $79 million to $146 million (1984 dollars). Equivalent estimates for BWRs are somewhat higher because of the greater degree of radioactive contamination that results from design differences. The cost for BWRs is pegged at $97 million to $195 million. The range of estimated costs for both reactor types reflects the range of assumed allowable worker radiation exposure (1–5 man-rems per year).

Deferred dismantlement and safe storage of a nuclear plant for 50 years, by allowing time for radioactive decay of much of the contamination, reduces the estimated cost range: $75 million to $96 million for a PWR and $98 million to $123 million for a BWR.

The entombment approach to decommissioning—sealing a plant intact for up to 100 years—produces an even lower cost estimate because of the elimination of much of the decontamination cost. Entombment and 100 years of surveillance for a large reactor is estimated to cost $64 million to $66 million for a PWR and $91 million to $94 million for a BWR.

Coming into focus

NRC's proposed new regulations on decommissioning will establish the legal basis for utilities to proceed with plans for funding and carrying out decommissioning projects when the time arrives. Most of the technology required for decommissioning is already in place. With the current rapid pace in development of robotics and automated remote operations, personnel radiation exposure will be substantially reduced in various decommissioning tasks. The open issues associated with decommissioning are peripheral, albeit important, including radioactive waste disposal capacity and cost, as well as the potential for life extension at nuclear plants. But the basic question of R&D interest—whether the industry has the tools and know-how to do the job—is not an issue, EPRI research managers agree. ■

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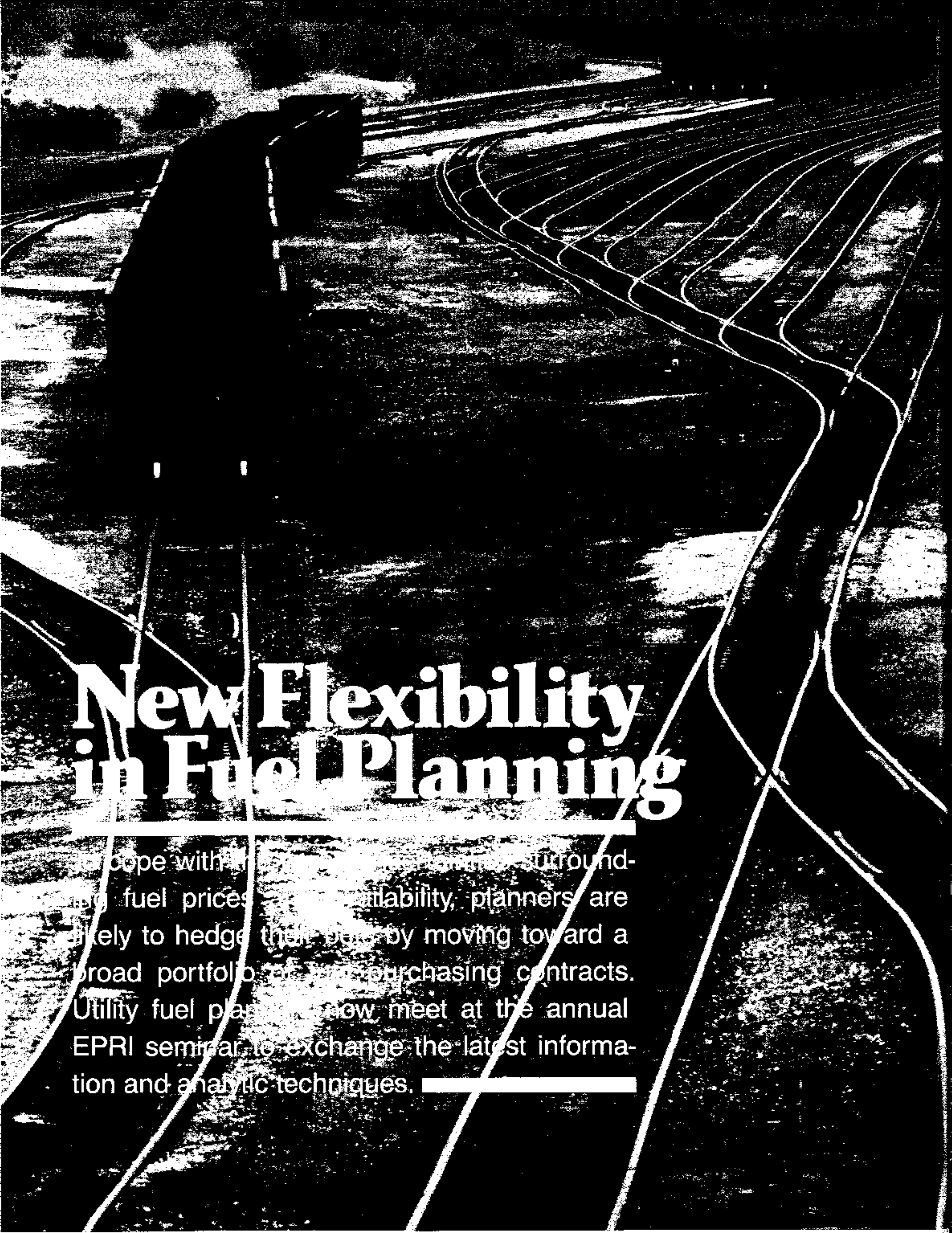
This article was written by Taylor Moore. Technical background information was provided by Adrian Roberts and Robert Shaw, Nuclear Power Division. Additional background information was provided by Christine Lawrence, Washington Office.



New Flexibility in Fuel Planning

To cope with [illegible] surrounding fuel prices [illegible]ailability, planners are likely to hedge [illegible] by moving toward a broad portfolio [illegible] purchasing contracts. Utility fuel pla[illegible] now meet at the annual EPRI seminar to exchange the latest information and analytic techniques.

Fuel supply planning commands a major role today because fuel costs have risen so sharply over the past decade—the nation's utility fuel bill has grown to more than $40 billion annually. With fuel now accounting for nearly half of total utility operating expenses, utility managers are focusing on fuel cost as an important point of leverage in controlling the cost of electricity production. This growing emphasis on fuel cost places a premium on methods and information that will help fuel planners more effectively manage uncertainty in tomorrow's fuel needs and resources.

Identifying and dealing with uncertainty was the central theme of the most recent EPRI fuel supply seminar, held in Kansas City this past October. These ongoing seminars (the next to be held October 8–10 in San Antonio, Texas) have become a major forum where EPRI contractors and others vitally concerned with the utility industry can address the current state of fuel information assessment and analytic methods development related to fuel demand and supply. This fourth seminar, organized for an audience representing the bulk of U.S. electric utilities, featured an integrated set of presentations on key issues and developments affecting major fossil and nuclear fuels, principally coal and gas. Discussions centered on uncertainty over coal prices and supply, due in part to the possibility of acid rain legislation that will constrain the emission of sulfur and nitrogen oxides from power stations, and on uncertainty about the near-term prices of natural gas and its long-term availability to utilities.

The keynote of the seminar was the observation that fuel price uncertainty is shaped by underlying uncertainties in demand and supply—the drivers of market conditions. Major uncertainties facing the utility fuel planner on the demand side are what fuels to buy, in what quantities, and for what periods of time in the future. On the supply side, uncertainties revolve around price trends and forecasts, fuel availability, transportation costs, and government regulations.

Taking sight of the difficulty in forecasting fuel prices, Ronald G. Wasson of Kansas City Power & Light Co. agreed that the uncertainty is real, but added that it is no stranger to the electric utilities and can be managed. According to Wasson, fuel planners should trade on the experience of other utility departments that are dealing more effectively with uncertainty. System load forecasters, for example, are giving up deterministic forecasting (point estimates) in favor of probabilistic methods, which produce a range of estimates and more accurately reflect the interplay among factors that govern utility load growth. Similarly, such methods can help identify and characterize the elements of uncertainty in fuel planning that arise *within* the electric utility system, such as changes in unit availability or the date that a new nuclear unit will come on-line. And they can also be used to describe and quantify fuel market uncertainty and risk.

Fuel price forecasts

The fuel planner must keep informed of trends in fuel prices and changes in fuel resource bases. Although price forecasts generated by energy models may help planners improve their subjective judgments about fuel supplies, William W. Hogan of Putnam, Hayes & Bartlett, Inc., pointed out the problems of blind reliance on models: "Using energy forecasts requires as much judgment and care as does producing the forecasts." Changing or conflicting forecasts can increase confusion for the user. Drawing on work of Stanford University's Energy Modeling Forum and EPRI's fuel forecast review project, which compared a number of oil and gas forecasting models, Hogan noted that the most important factor explaining the errors found in nearly all the forecasts was the inability to correctly anticipate economic growth and, with it, fuel demand. Were it not for this major problem, most forecasts would have performed quite well.

Hogan went on to point out that fuel planners face additional difficulties in using forecast information. There are definitional variations: one model will use the price of oil "as loaded in the Persian Gulf"; another, "as delivered in New York." There are quantitative variations: one model will use the cost of gas "as produced today"; another, gas "for future delivery." Further, forecasting assumptions about such factors as depletion and productivity can vary widely. Although the models may identify the uncertainties involved, the user cannot simply accept forecast numbers as final truth.

Planners also need a descriptive theory of the model, a "story" that tells what is happening within the model and how to put the numbers into a decision context. Hogan pointed out that judgmental factors regarding uncertainty must be integrated into forecast models more explicitly.

Coal price forecasts received a large share of attention during the seminar. Price forecasts prepared by major private and public agencies over the past six years not only have varied greatly from each other but also have tended to change considerably from year to year. Two reasons for these differences, noted James M. Speyer of Putnam, Hayes & Bartlett, are difficulties in predicting how individual utilities will react to specific economic incentives to solve emission control problems and difficulties in making the key assumptions that drive the forecasts—electric energy growth rates and oil and gas prices.

Coal prices generally have not gone up as predicted, observed Seth I. Schwartz of Energy Ventures Analysts, Inc., because the fundamental assumptions underlying most price forecast models have not accurately described the coal industry. What these models have overlooked are the fundamentals of the coal industry itself. A closer analysis of coal companies, reserves, and markets and the changing patterns of mining investments and methods will yield a more reliable forecast of coal production and prices. With this critique of coal price forecasting models, Schwartz focused the seminar's attention on coal production and price trends in four supply regions.

Coal supply and prices

In the northern Appalachian region, a tremendous increase in labor productivity in underground mining has changed the coal market and the outlook for coal prices. The market is being led by large new underground operations in northern West Virginia, which are producing coal at a fully loaded price of $36 per ton. In contrast, the economics of opening a new strip mine in central Pennsylvania call for about $34 per ton just to cover capital costs. Thus, surface mining in the region will continue to lose market share to underground mines.

Central Appalachia is the principal source of eastern low-sulfur coal, which could be in great demand if utilities are forced to meet lower sulfur emission regulations. Thus, production in this region is a crucial factor in analyzing the effects of proposed legislation. In the last eight years the region's coal industry has seen a great increase in labor productivity, with higher-cost mines replacing lower-cost operations. The region has changed, too, from a supplier principally of lower-ash coal for steel making to a producer of higher-ash coal for utility boilers. A new mine can be developed on the basis of coal at $33 per ton.

Another high-capital, low-variable-cost source of coal is mountaintop removal, which can yield coal at a fully loaded price of $36 per ton. According to Schwartz, there is tremendous productive capacity in existing mines in the central Appalachian region today, as well as in recently acquired reserves that can be opened in the future at today's coal prices.

In the Illinois Basin a depletion of reserves has occurred, especially in low-cost Illinois surface mines. The choice for their replacement is seen not as new large underground mines but as new smaller mines in Indiana and western Kentucky. For utilities willing to contract for 300,000 tons a year instead of 2 million tons, there are enough low-cost mines to maintain competitive prices.

Looking at the Powder River Basin, Schwartz told the seminar that existing mines have 265 million tons of productive capacity, more than twice existing production. New coal is selling for less than coal from existing mines. This excess capacity means that unless acid rain legislation causes a truly massive switch to western low-sulfur coal, there is little reason for coal prices to rise.

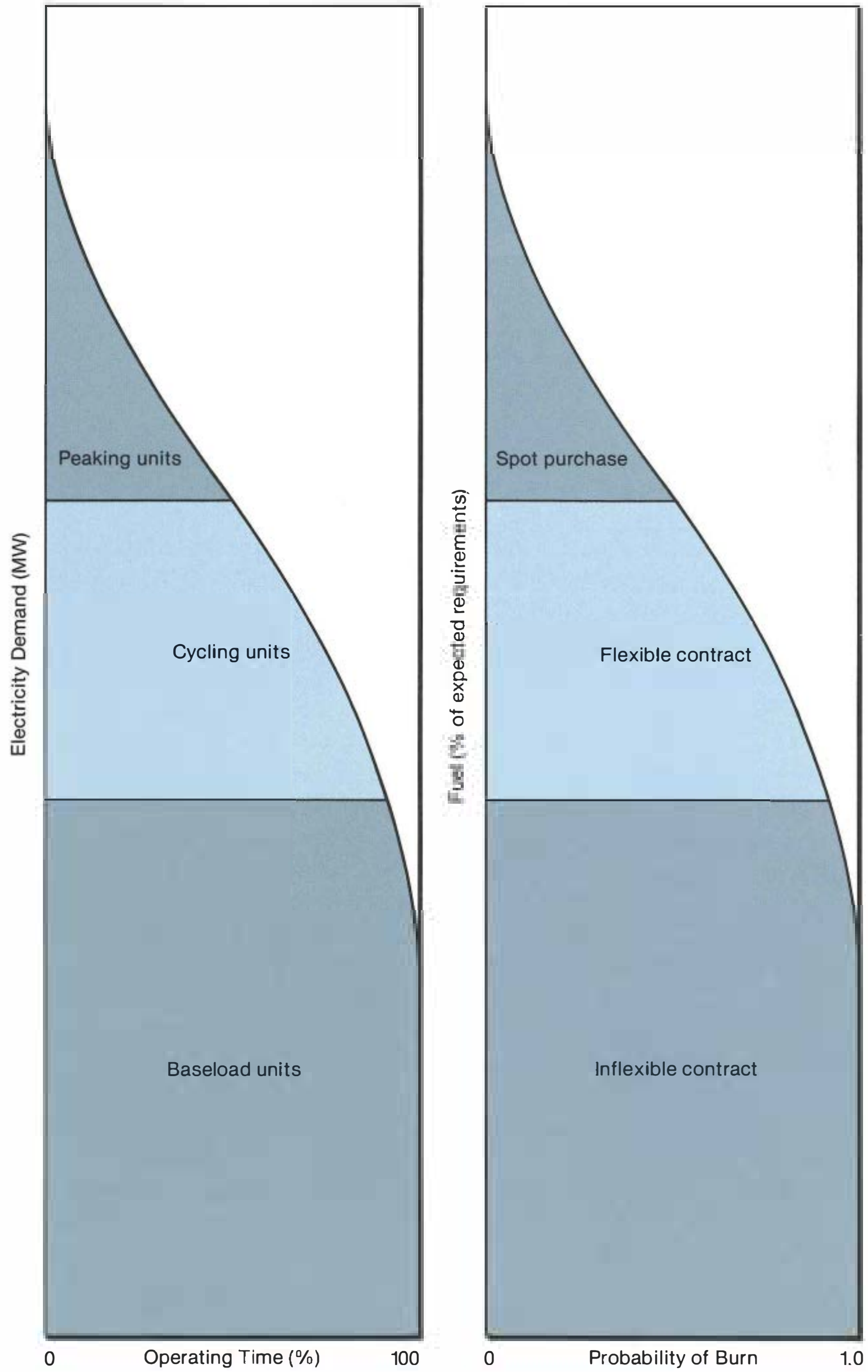
Demand uncertainty is no stranger to the coal industry, as seen in forecasts that have tended to overstate domestic coal demand. Bruce A. Gulliver of NERCO, Inc., argued that these forecasts erred by not considering the larger economic system in which the coal market operates. He went on to describe the major elements of the demand uncertainty now facing the coal industry.

Noting that utility generating capacity margins have fallen for the first time in years, Gulliver suggested it may be time to revise load forecasts upward and to consider the impact of adding new units. As the nuclear option appears less likely, a related question is how many nuclear units now under way will be abandoned. Overall, the demand for electric energy will remain as the greatest uncertainty affecting coal demand.

The unknowns of acid rain legislation also make the analysis of utility coal de-

Analogy for Fuel Planning

The problem of getting a good mix of fuel contracts has an interesting parallel in the more familiar process of utility capacity planning. To serve electricity demand reliably, utilities must have a solid, inexpensive baseload capacity available, backed up by cycling plants for intermediate load and expensive, peak-load generation for the small top increment of demand. Likewise, the utility fuel planner commits to inexpensive, inflexible, long-term contracts for the fuel he is sure will be required and orders additional fuel through flexible contracts, which are more expensive but allow the utility to buy less if its fuel requirements turn out to be lower than expected. Additional needs are satisfied by purchases on the highly price-variable spot market, which imposes no commitment on the utility.



mand very difficult. Whether legislation will change total demand or shift demand among coal supply regions will depend on the details of the laws enacted.

Foreign competition is another factor that demands serious attention. In the world coal market, low-sulfur coal is abundantly available from South Africa, Australia, Colombia, and Canada. Excess capacity overseas in utility boiler coal production will grow to over 30 million tons in the near term. Gulliver added that foreign coal has already made serious inroads into lower midwestern and southern U.S. markets.

Finally, greater competition among railroads following the industry's deregulation in 1980 is affecting the cost of transporting coal. Because transportation costs can be a significant factor in the price of delivered coal, trends in this area will play an important and still uncertain role in shaping regional coal production patterns.

Changing markets for natural gas

In developing long-term strategies for fuel supply planning, electric utilities should focus on natural gas as an evolving competitive fuel. The unfolding gas market and the uncertain status of gas as a utility fuel resource were previewed by Hillard G. Huntington of Stanford University's Energy Modeling Forum. He emphasized that natural gas is sold within a market governed by a set of special institutions. It is important to recognize these rapidly changing institutional factors because today's gas market seems to be sending conflicting short-term and long-term price signals. For example, although the present gas market appears to be constrained by demand, the price of gas has risen dramatically, even in the face of growing surplus capacity. This perverse market response has occurred because the price of gas is strongly influenced by pervasive regulation and long-term contracts. Other panelists provided details of utility gas market developments for the short and long terms.

Electric utility demand for natural gas is significant to the gas market not only for its size—almost 25% of total consumption in some years—but also for its flexibility and favorable load factor. Yet during the past decade electric utility consumption has gone through wild swings as a result of shifts in federal gas policy. It is only natural for electric companies to view natural gas as a boom-or-bust fuel resource. With this introduction Catherine Good Abbott, Interstate Natural Gas Association of America, outlined signs of change in the gas industry and noted their marketing implications for utility gas customers.

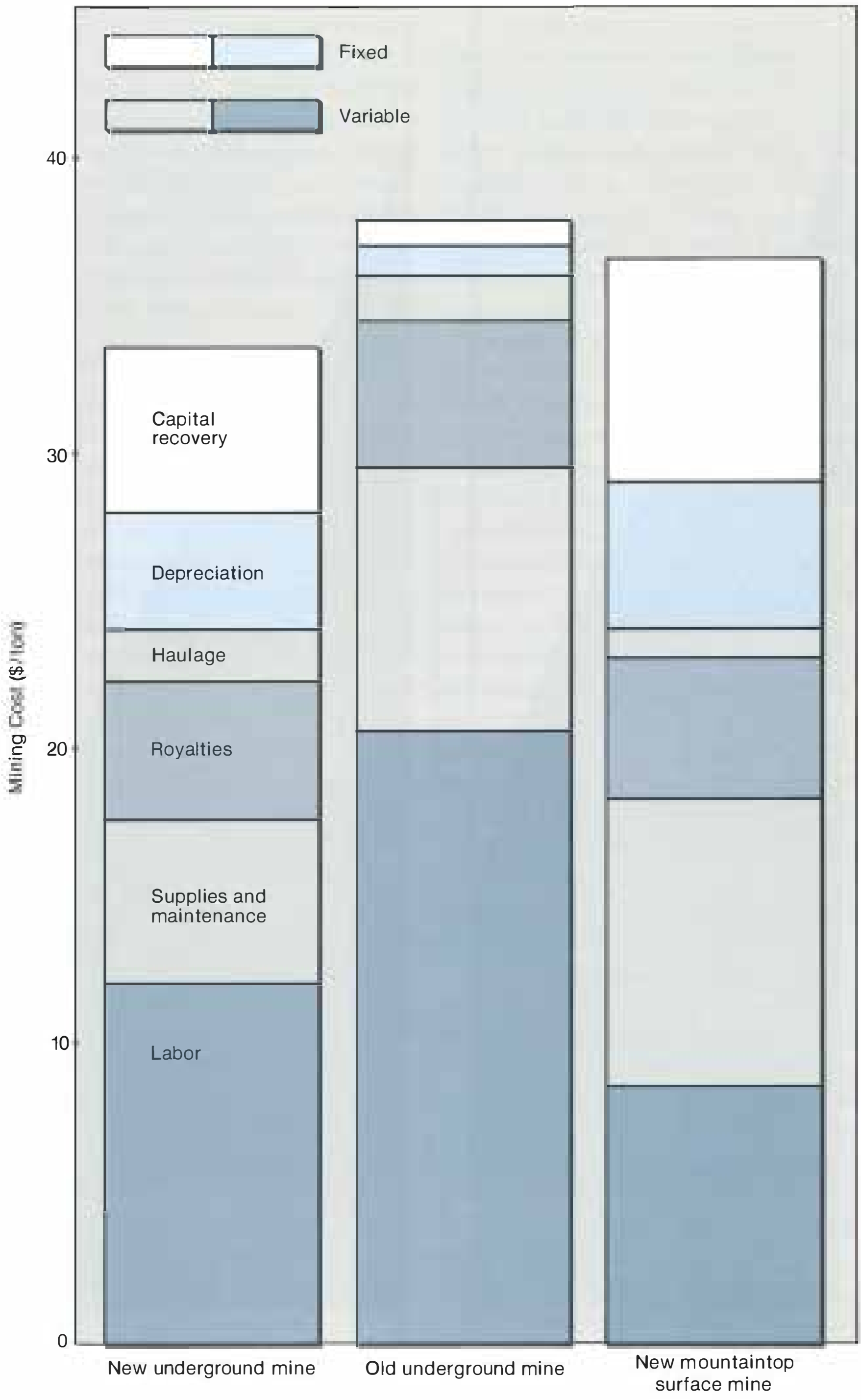
The gas business is undergoing a difficult transition to a more competitive market, according to Abbott, a process that requires important institutional, marketing, and regulatory changes. Although the outlook for gas supply is good for the rest of the decade, the price picture is clouded by uncertainties of decontrol in 1985. The market will put downward pressure on prices while contract provisions will exert upward pressure.

At the same time, less regulation, new institutions, and a growing emphasis on gas marketing by pipelines, local distribution companies, and independent brokers will create new gas-purchasing options for electric utilities to explore. The uncertainty of demand suggests that utilities should seek a portfolio of sources to strike a balance between price and reliability of supply. In short, Abbott said, natural gas has become a much better supply option, but electric utilities need to learn more about the gas business to make good choices among the new options.

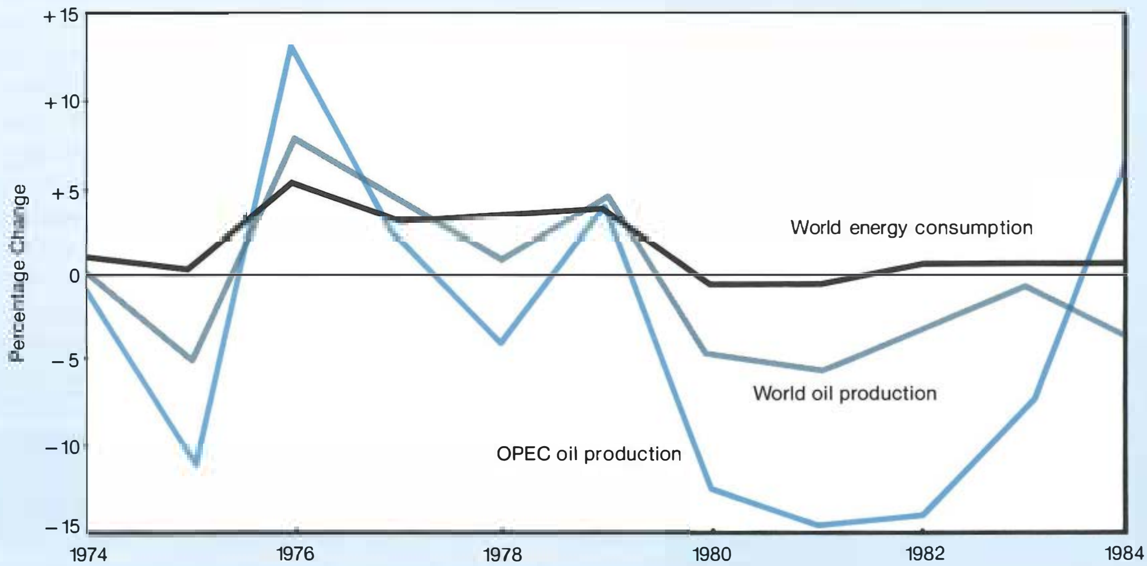
The transition to deregulation in the gas market means that while electric utilities should focus on price rather than availability, in the long run they should stay alert to changes in the underlying resource base. As suggested by several factors, a shrinking resource base or more costly production from new sources will raise gas prices over the longer term. Addressing this prospect,

Shopping for Coal Contracts

The price of coal from any particular supplier is influenced by a number of cost factors, as shown in this example from the central Appalachian region. In an old underground mine, the fixed costs are likely to be low because most of the capital equipment was purchased years ago at preinflationary prices; however, depletion of resources in old mines may require mining of thinner coal seams, which reduces productivity and drives up labor costs. For new mountaintop surface mines, the relatively low labor costs trade off against higher capital equipment costs for large earthmoving machines. Mine-to-mine variations and differences in the way these factors react to outside influences (such as inflation) are great enough to encourage utility fuel planners to shop around carefully when initiating new coal supply contracts.



THE OPEC MULTIPLIER



At first glance the prospects of the Organization of Petroleum Exporting Countries (OPEC) look anything but promising. Since 1980 OPEC has experienced four consecutive years of sharply falling oil production and revenues. Nonetheless, the very factors that reduced OPEC oil demand can also cause it to rise rapidly, precipitating a tight world oil market in which energy prices could once again soar. The driving force behind such a swing is an effect that has been called "the OPEC multiplier." According to Bijan Mossavar-Rahmani of Temple, Barker & Sloane, Inc., this is how the multiplier works.

When world energy use started to fall abruptly in 1980, world oil production dropped even faster, with the steepest decline occurring in OPEC production. What accounted for this sharp drop in demand for OPEC oil? Just as oil is the swing, or marginal, fuel in the world energy system, so OPEC is the swing supplier of oil to oil-consuming countries. As these countries begin to use oil supplies faster, they first turn to local sources, then to non-OPEC foreign suppliers, and finally to OPEC for the balance of their marginal oil supply. Conversely, as demand for oil begins to decline, consuming countries first reduce their use of OPEC oil. Here's the significant result: a small percentage increase in world oil demand leads to a larger percentage increase in demand for OPEC oil, and a small decrease in world oil use prompts a larger percentage drop in demand from OPEC. That is the OPEC multiplier at work.

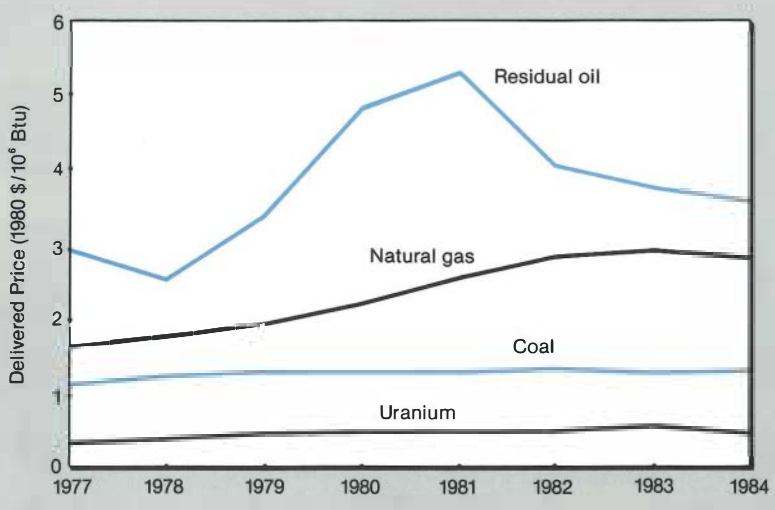
Historically, OPEC has accounted for about 50% of world oil production. But as a result of the multiplier, a 5% decline in world oil demand leads to a 10% drop in OPEC output. Large fluctuations in world oil production since 1973 have confirmed this multiplier effect on OPEC as the swing supplier of oil to the world.

The significance of the multiplier to utilities today is that it works just as effectively in reverse. Given even a small increase in world primary energy consumption annually for the next few years, there would be a larger percentage rise in world oil production and, ultimately, a sharp rise in demand for OPEC oil. Thus, with increased consumption, the world oil market could repeat the 1970s pattern.

It could take only a small disruption in oil supply or the expectation of an impending shortage to trigger a round of panic buying, and as before, OPEC would be in a position to capitalize on the rising price of oil. War, civil strife, political unrest, or terrorist turmoil in the Persian Gulf area could be the disruption that triggers an oil panic. At the very least, falling oil revenues over the next several years could induce OPEC, even without a disruption, to drive up oil prices when the world market for oil tightens. The OPEC multiplier is the mechanism making this possible. From a utility perspective, the multiplier effect strongly reinforces the general perception of oil as an uncertain and risky fuel. □

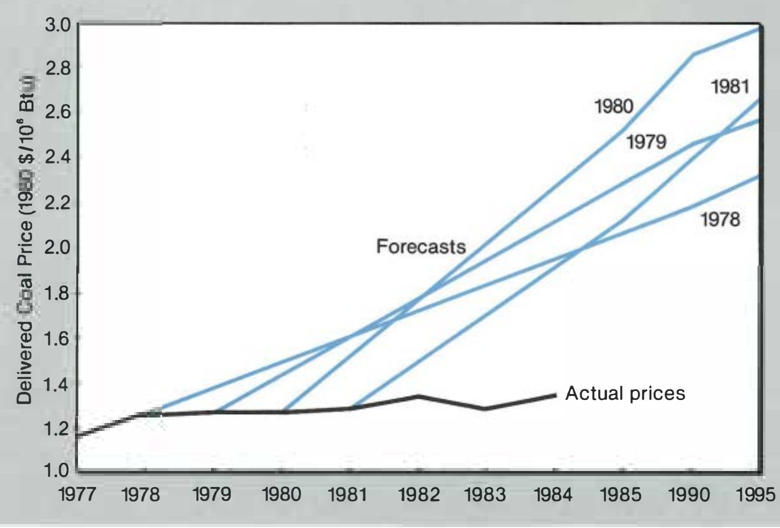
What Happened in Fuel Prices . . .

A review of national average (as-delivered) fuel prices points up a few of the many factors that the fuel planner can neither control nor precisely predict. The delivered price of residual oil in the United States generally followed world oil price trends, which were driven primarily by the supply shocks of 1973 and 1979. The price of natural gas, responding to phased decontrol instituted by the Natural Gas Policy Act of 1978, rose gradually to more closely track oil prices by 1983. The large number of coal sources, sustained competition from other fuels, and lower-than-expected demand from industry combined to keep coal prices from rising significantly. A persistent supply-demand imbalance resulting from nuclear construction slowdowns after the Three Mile Island accident caused the minemouth price of uranium to decrease by almost half from a 1979 peak; however, increases in fuel preparation costs—especially enrichment costs—offset this decline to level the as-delivered price, shown here.



. . . and What Didn't

Sharp increases in the coal price forecasts of the late 1970s and early 1980s reflected expectations of increased utility demand for coal and a predicted rise in material and labor costs. In fact, faltering utility load growth put a damper on demand, and costs of coal production declined with continued mechanization in the mining industry and improved methods of mine management. Effects of the Staggers Act of 1980, which some had predicted would drive transportation costs out of sight, also turned out (for most routes) to be less dramatic than anticipated.



1985 EPRI Fuel Supply Seminar *San Antonio, Texas*

The 1985 seminar will address the broad theme of fuel supply in utility planning, with individual sessions as noted in the agenda below. For further information, contact Jeremy Platt at (415) 855-2628.

October 8

Utility Fuel Demand Uncertainties

- Capacity margins, generation options, and planning risk
- Regional fuel use implications of generation mix
- Utility example: fuel burn uncertainty

Fuel Forecasts and Assumptions

- International economic phenomena affecting fuel planning
- Fuel market forecasts
- World crude oil markets

October 9

Residual Fuel Oil and Natural Gas Markets

- Residual fuel oil market behavior
- Structural changes in natural gas markets
- Influence of changing industrial gas demand

Coal in Environmental Planning

- Scrub-switch decision uncertainties
- Premiums for low-sulfur coal

October 10

Coal Market Conditions and Implications for Procurement

- Western coal markets and industry changes
- Rail transport pricing case studies
- Changing commercial arrangements in coal production and transportation
- Utility example: integrated fuel and utility planning

Workshop Session: Canadian Energy Purchases

John J. Schanz, Jr., of the Congressional Research Service, Library of Congress, and Klaus P. Rose of Sherman H. Clark Associates, Inc., predicted increasing production costs, since gas discovery technology will advance no faster in the future than in the past.

Gas production and use will probably decline even if gas prices rise faster than general inflation. A decline in conventional production, including imports and other sources, in the lower 48 states by the year 2000 implies decreasing availability of natural gas for electric utilities and industry. Higher-priced substitute fuels could slow this trend, but gas prices would still be significantly higher under such conditions.

A more optimistic projection of conventional gas production in the lower 48 might result from other conditions, such as faster technological progress in drilling or a move by the gas industry to operate with lower inventories by reducing its reserve-to-production ratio. The emergence of a more extensive North American international gas market would be another favorable condition, and judging from Canada's recent pricing strategy to sell more gas to the United States, this trend may already be starting to develop. Although Rose's projection of gas supply incorporates an expansion of Canadian imports to the year 2000, there is still considerable uncertainty regarding this development.

New analytic tools

One of the major objectives of the fuel supply seminars is to provide utilities with better information about the factors most likely to influence their fuel prices and plans. But important as they are, fuel prices and availability are not the only factors that affect fuel planning. The planner must also understand the uncertainty in fuel burn requirements.

Michael S. Hyrnick of Ohio Edison Co. and James A. Hodde of Management Analysis Co. told the seminar about a probabilistic model for fuel requirements forecasting being used by Ohio Edison. According to Hyrnick, the utility developed the model to help quantify the risks involved in fuel procurement. The model sheds light on fuel planning risks that were formerly ignored or not well understood, much less quantified. As an example, Hyrnick demonstrated how his company has been able to quantify the uncertainty in some of its units' fuel burn resulting from uncertainties about load growth, unit availabilities, power interchange, and the startup of a nuclear unit.

Fuel burn and fuel forecast uncertainties have combined to make fuel procurement planning difficult. One solution to this problem is to develop analytic tools that give utilities the ability to explicitly evaluate both sources of uncertainty simultaneously. Such tools would allow risk analysis to be included in the development of more flexible fuel procurement strategies.

Richard B. Fancher of Decision Focus, Inc., along with coauthors James F. Wilson, also of Decision Focus, and Howard A. Mueller of EPRI, described a new EPRI model that can accomplish this task. By explicitly incorporating the kinds of uncertainties described by Hyrnick and Hogan, the EPRI Contract Mix Model will allow fuel analysts to evaluate alternative fuel contract mixes and strategies, to identify fuel risks, and to assess the value of different approaches to contract flexibility for their systems.

Through a series of simple case examples, Fancher demonstrated how uncertainty in fuel requirements and prices can be represented in the model, and illustrated the kinds of insights about contracting options it can generate. The model enables a utility to apply the type of fuel market information presented during the seminars in designing its contracting strategy. In the case examples, Fancher explained how the model could be used to relate the amount of uncertainty in a unit's fuel requirements to the amount of flexibility a utility might select in its supply contracts. One major conclusion to emerge from the modeling examples was that under some circumstances a utility could substantially reduce the risks of high fuel costs at very little increase in average costs by carefully matching its contract flexibility to its burn and price uncertainty.

Directions for the planner

The objective of EPRI's fuel supply seminars is to give utilities better information to use in developing their fuel plans and strategies. While the seminars cannot eliminate overall market uncertainty, they can help by providing a better structural framework for understanding *utility* fuel markets.

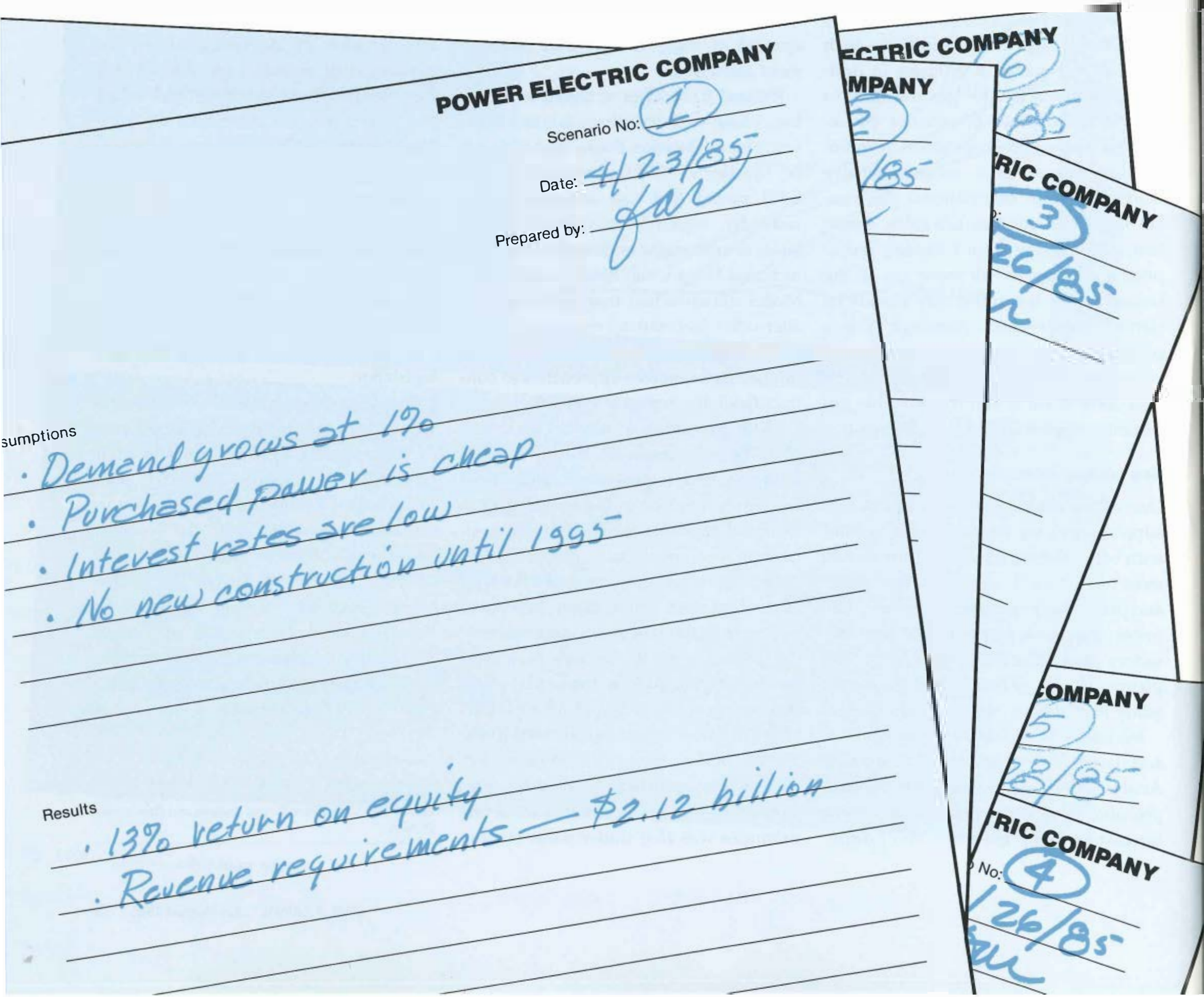
The information must still be applied to each company's own system. The fuel supply planner must continue to seek out the best planning and operating data from his own utility to establish the fuel requirements of individual units. The planner must carefully use the seminar information about trends in fuel prices and availability to understand his own fuel markets and formulate an appropriate fuel procurement strategy. He must weigh the effects of deregulation in the railroad industry on delivered fuel prices and of deregulation in the natural gas industry on gas availability and price. The planner must also compile a set of specific alternatives to deal as effectively as possible with potential acid rain legislation.

In many of these processes new analytic methods can greatly help the planner evaluate alternative decisions and their potential consequences. Although such tools cannot remove the risk inherent in an uncertain world, they can be used along with judgment and experience to identify and better manage the uncertainties and risks in fuel supply planning. Given the magnitude of today's fuel costs, this effort can play a major role in developing and maintaining the competitive edge of electricity. ■

This article was written by Francis Kovalcik, science writer. Technical background information was provided by Howard Mueller and Jeremy Platt, Energy Analysis and Environment Division.

UPM: Modeling at the Corporate Level

The interrelationships of many separate corporate decisions—from regulation to pricing to alternative expansion plans—can be charted through the Utility Planning Model. The output is focused on the corporate bottom line.



Two important aspects of electric utility planning during the past 15 years have been a trend toward greater uncertainty and the recognition of interactions among planning factors previously thought to be unconnected. This combination of uncertainty and interaction was first evident early in the 1970s. It became a central concern in the utility planning process and eventually stimulated EPRI research that has now produced an integrated utility planning model.

The necessity for integration stemmed from the realization that no aspect of utility system operation is any longer functionally independent. For example, increases in the price of electricity tended to curb demand growth, and this reduction in turn caused construction plans to be scaled back or delayed. Such changes in construction plans induced a variety of consequences, including cutbacks in financing needs and tax payments, as well as ballooning interest charges over longer time periods. Clearly, comprehensive planning was needed that would take into account electricity demand, price changes, environmental and economic regulation, inflation, and interest rates—the increasing web of factors that affected the performance of utilities and their costs of operation.

In the late 1970s, corporate planning models became a specific focus of the Utility Modeling Forum, an EPRI project established earlier to investigate various utility models, their applications, and their capabilities. The outcome of the forum's study of corporate modeling was a recommendation to develop what is now called the Utility Planning Model (UPM).

The new project started in 1980, organized with an advisory structure of corporate planners and modelers to ensure the practicality of what followed. Commonwealth Edison Co. cosponsored the work, making available its own computer and the full-time services of a planning analyst. Arthur Andersen & Co. carried out the project under EPRI contract. The resulting model, UPM, simulates all the major functions considered in utility planning—load forecasting, system planning, production costing analysis, fuel supply planning, financial analysis, and rate and revenue analysis.

Functional overview

Although functioning as a single model, UPM consists of five logically distinct models. The principal one is the so-called projection model; the other four deal with data entry, preprocessing of data, validation of values for some of the key entries, and comparison of results from the projection model.

The projection model includes modules that correspond to various functional areas of an electric utility: load and load modification, generation planning, production dispatch, fuel costs, construction costs, revenue, analyses of other entities (e.g., subsidiaries, nonutility operations) and their consolidation, plant and other expenses, and financial analyses (including tax and regulatory matters). In addition to these modules, the model contains a report module, which consolidates results into a convenient and useful format.

All these modules are linked, and each module must be run for a given year before any can be run for the next year—a round-robin approach that ensures a complete and integrated analysis. Also, several feedback capabilities are incorporated in the system. For example, changes in production cost—and therefore in price—are likely to produce a change in demand growth, and system plans can be adjusted accordingly.

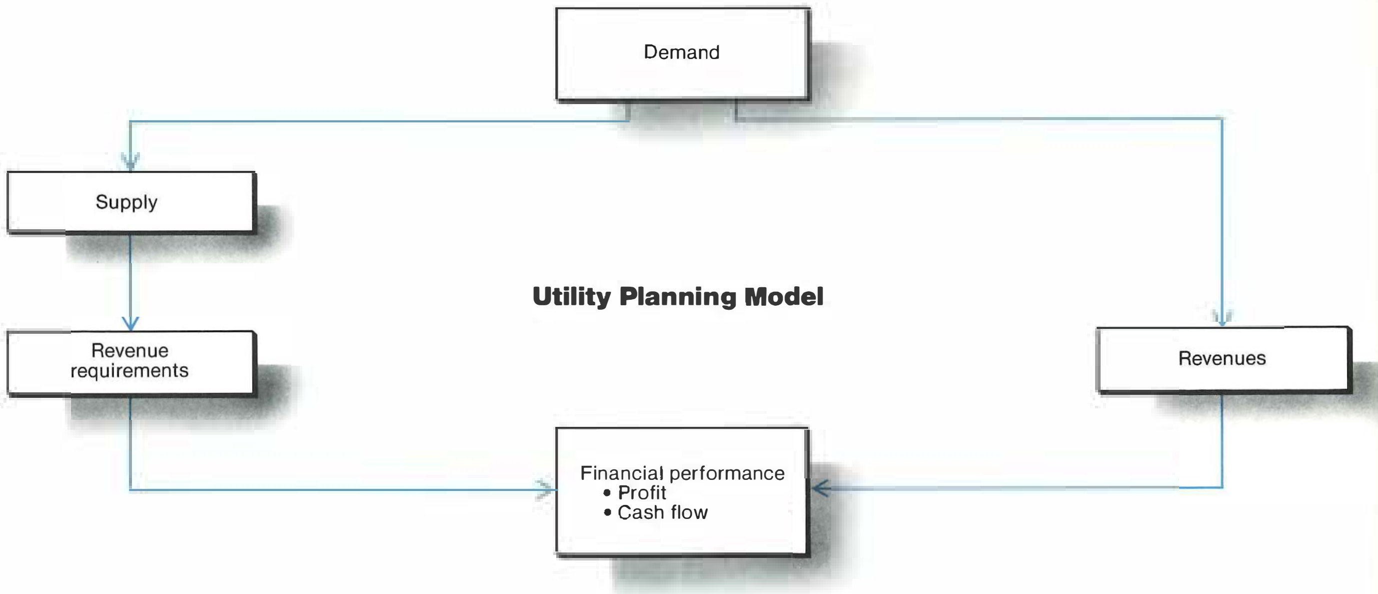
In addition to its comprehensive and completely integrated structure, UPM provides an enormous amount of flexibility and adaptability to individual utility situations. A special design feature allows users to increase or reduce the size of data arrays conveniently without modifying the computer programs themselves. The model can thus easily be structured to encompass varied corporate organizations, including multiple operating companies and jurisdictions, power pools, individual construction projects, and specialized financing instruments. In the opinion of the Commonwealth Edison analyst who was assigned to the UPM project, this capability is particularly useful for utilities that cross state lines, answer to more than one regulatory body, or otherwise have complex organizational structures.

A practitioner's tool

Although Commonwealth Edison was the original UPM user, four other utilities also served as test sites—Florida Power & Light Co., Georgia Power Co., Northeast Utilities, and Wisconsin Electric Power Co. Project advisory representatives from these and over a half dozen other utilities provided constant checks on the authenticity and practicality of the model.

Commonwealth Edison has already used the model to produce a number of studies, among them a 20-year projection of cash requirements and electricity prices, which it presented to the Illinois Commerce Commission in support of the utility's position on rate increases. Commonwealth currently uses UPM on a regular basis to support a wide range of planning functions, including analyses of alternative scenarios for introducing new nuclear power units into the utility rate base with minimal impact on customers. Wallace Behnke, vice chairman of Commonwealth, speaks enthusiastically of UPM: "There's no doubt that this is a very powerful tool that can be used for widely different problems. UPM has enhanced our understanding of the interrelationship of decisions to an extent not previously possible."

Another of the original utilities working on UPM, Georgia Power, replaced a corporate model already developed in-house, because it found UPM to be more efficient and user-friendly. Robert Lewis, economic evaluation manager for the utility, says the company was looking for "something that we could run quickly, that was adaptable to our system, that was written in a user-friendly language, Using the Utility Planning Model to project various income and expense assumptions into the future, analysts can derive values for such important measures of financial performance as profit and cash flow. These in turn can be the bases for analyzing rate increase requirements or needs for external financing. A demand forecast is key. Demand can be satisfied by various electricity supply options with differing revenue requirements—fuel and operating costs, construction costs, and financing costs. The demand forecast also defines a pattern of electricity sales—the revenues that can be expected under the existing rate structure. These parallel streams of calculations converge to produce the needed estimates of utility financial performance.



and that had greater capabilities in a number of areas we were particularly interested in—regulatory analysis, price and price effects, and alternative expansion plans."

Georgia Power also used UPM to investigate financing for a $7.2 billion nuclear power plant scheduled to come online in 1987. As part of the same study, the company has investigated several longer-term generation possibilities, including pumped-hydro storage and a new coal-fired power unit for the 1990s. Altogether, Georgia Power has run more than 40 different scenarios on UPM, using a variety of assumptions to predict what the future may bring. If the utility were still using its old corporate model, Lewis says, "we would be talking about a lot more time and a lot more effort in terms of both overtime and the number of runs that had to be made." He adds that "one of the big strengths of this model is that it allows you to simulate the regulatory treatment your company expects to get."

UPM has now been adopted by Georgia Power's companion operating companies within The Southern Company. Alabama Power Co., Gulf Power Co., and Mississippi Power Co. will each have a separate UPM model, and the holding company will have a consolidated model for the entire system. UPM is thereby being used to create a series of building blocks for a comprehensive, systemwide model.

Several dozen other utilities are also becoming UPM practitioners, adapting the model to their individual data bases, regulatory environments, and financial circumstances. In addition, EPRI is organizing a users group of interested practitioners to foster communication and support for the model. The group is sponsoring such activities as a newsletter, biannual meetings, a hot line to handle user questions, and basic maintenance of the model.

The bottom line

According to Lewis Rubin, EPRI project manager, UPM provides "a rigorous capability to simulate the consequences of alternative strategies. It's a planning model that focuses on the corporate bottom line, as well as on utility revenue requirements, the more conventional measure." UPM reports on cash flow, revenue streams, revenue requirements, the need for external financing, and overall financial performance.

As a comprehensive planning model, UPM is designed to present a complete picture of a utility. The model represents and integrates virtually all the current planning and operating concerns of a utility—from load projection to financing and regulation. UPM is thus a valuable aid to decision makers as utilities decide on strategies for the future. ■

This article was written by Stephen Tracy, science writer. Technical background information was provided by Lewis Rubin, Energy Analysis and Environment Division.

Sweden Looks to Its Energy Future

Hans G. Forsberg, president of Sweden's prestigious engineering academy, discusses two topics close to his heart—the academy itself and its recent controversial study on the future of Sweden's energy system.

Housed in a historical building erected in central Stockholm in 1898, the Royal Swedish Academy of Engineering Sciences (Ingenjörs Vetenskaps Akademien, or IVA) is the oldest engineering academy in the world. Created in 1919 to promote the engineering and technical sciences and to recognize their contribution to society, the academy is composed of both Swedish and foreign scientists, researchers, economists, and engineers from academia, industry, and government.

Each Swedish member is elected to one of 11 divisions, which focus on specific aspects of the engineering discipline; foreign members are simply members of the academy as a whole. Chauncey Starr, EPRI's founding president and director of its Energy Study Center, has been a member of the Swedish Academy since 1973.

Because academy rules say that there must be 275 Swedish members under the age of 65, whenever a member reaches that age, another younger member is elected. "Academicians tend to be rather long-lived," Forsberg quips. "At the moment, we have about 500 Swedish members, 275 younger than 65 and 225 older. We also have 150 foreign members." The existing academy membership nominates and elects the new members.

The academy also supports the Industrial Council, a group of 300 representatives from Swedish industry, which makes recommendations in matters of engineering and technical research. The council provides about 30% of the academy's annual budget, which corresponds roughly to $5 million (U.S.). Another 10% of the budget comes from government grants, and an endowment provides an additional 10%. "The rest we earn," Forsberg states. "We charge for some of the conferences and meetings we hold, we sell our publications, and we also undertake studies contracted by the government, industry, and foundations. However, I should emphasize that we are a completely autonomous organization."

What, specifically, does the academy do? Forsberg smiles before responding. "I always answer that question by stating what we don't do: we don't run any laboratories, and we don't financially support any outside research. We provide an intellectual forum on questions of engineering and science, and we hold many meetings. The academy is a meeting place—for people and ideas. Last year we held 800 scheduled meetings at the academy, and probably 25,000 people passed through our doors. This is how the ideas get passed on."

Other ways academy members can pass along their in-depth knowledge and thoughtful ideas are through joint studies with government and industry, through the establishment of new research entities, and through the international exchange of information on research and development. The IVA has close contacts with the National Academy of Engineering in Washington, D. C., and sponsors many international seminars both in Sweden and abroad. Forsberg notes, "We are interested in international research because Sweden is a very small country. We produce about 1% of the world's research results, but we would like to make use of 100%. Through international collaboration we can."

The day-to-day administration and management of the academy is the responsibility of the president, who is also given the title of professor. Forsberg has been president of IVA for the past two years. "It is a formal appointment for six years, but my four predecessors all stayed on as president until the age of 65. It is remarkable to think that there have been only five presidents since the academy opened its doors." Asked about his background, Forsberg replies, "I am a chemical engineer by training, but I have had a very mixed career. I have worked in research, I have been an international civil servant in the nuclear energy field, and I have been president of a shipyard; so my background is in research, industry, and management."

There are 80 staff members employed at IVA, and they coordinate the studies, arrange meetings and conferences, and disseminate information on Swedish research and technology. As at many research organizations, the principal form of work at the academy is the investigative study. The studies are the result of interaction between the academy staff and the individual members and are produced by working groups that include staff personnel, academy members, and outside experts. Earlier academy studies have explored such topics as surface chemistry, marine technology, energy conservation, and computer technology.

The academy study that is currently receiving the most attention in Sweden and abroad bears the English title "Sweden's Future Energy System." Interest in this new study is high in the international energy community because the study shows the economic necessity for nuclear power if an industrialized nation is to remain internationally competitive. The study warns the Swedish government that without the cheap electricity provided by nuclear power, the nation's industries will suffer.

The Energy Study

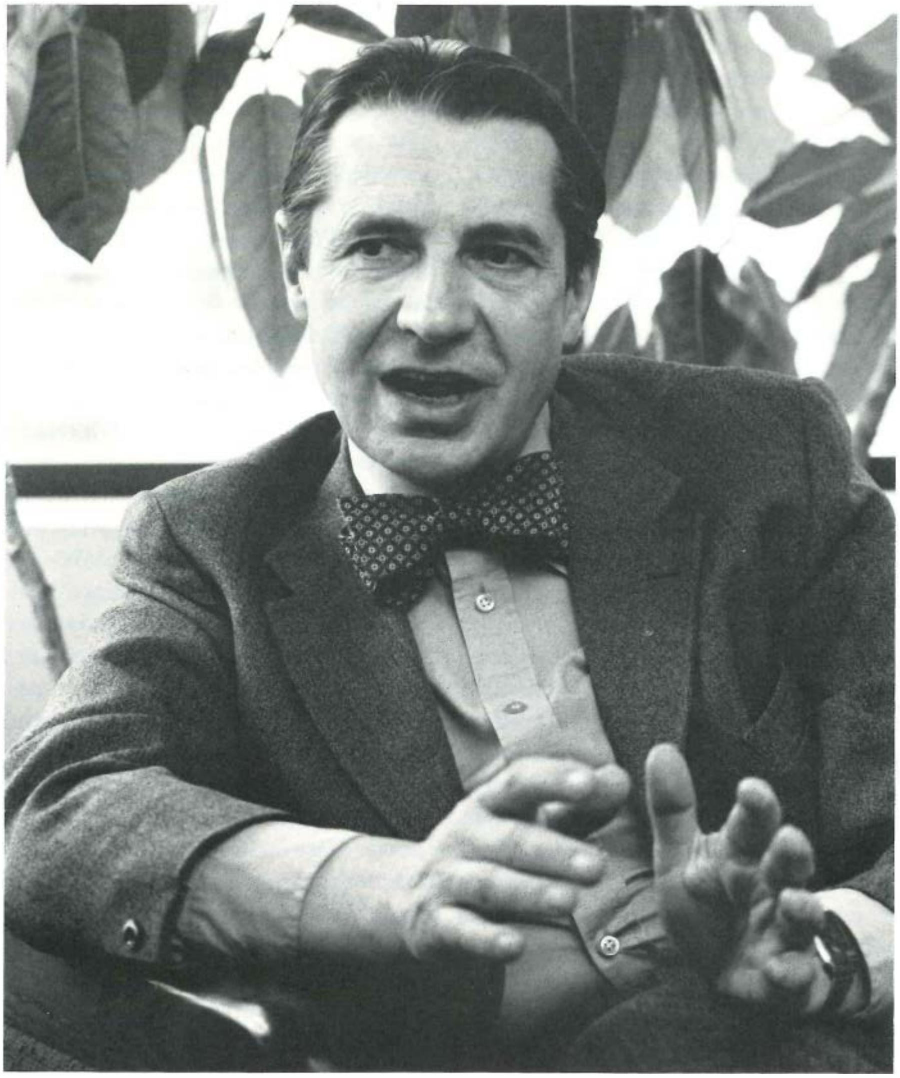
To understand the recommendations of the academy's study, the reader needs some background on Sweden's energy needs. As in many western nations, energy supply became a national issue in Sweden as a result of the oil crisis in the early 1970s. The Swedish political scene before the 1976 elections was charged with questions about how the nation could meet its energy needs through domestic resources. One political party opposed the use of nuclear power, counting on the strong antinuclear movement to give it political clout.

"When the Three Mile Island accident occurred in the United States in 1979, Sweden was at a very vulnerable point in its energy debate," Forsberg explains. "So much argument had occurred that the political leadership decided to halt all political discussions on the future of nuclear power in Sweden and put the question to the Swedish people in a referendum vote." Yet, in retrospect, that 1980 referendum appears to have created more questions than it answered. The people voted that all 12 nuclear units planned for Sweden be completed, that no further units be built, and that the 12 units eventually be phased out.

The vote resulted in an energy policy decision approved by the Swedish parliament in 1981. Among other things, the policy goals stated that development would be geared toward an energy system based largely on renewable and indigenous sources of energy; that rational use of energy conservation would be promoted; that the use of oil would be reduced, partly through energy conservation measures and partly through substitution of other types of energy; that nuclear power would be used until it was phased out in the year 2010; that influence on the environment and people would be limited; and that the cost to the national economy would be as low as possible. But one of the problems with these policy goals, the academy study points out, is that "no clear lines are presented or discernible as to how the first goals are to be compatible with and balanced against the last two."

It was a primary objective of the academy's study, therefore, to look at the economic impacts of phasing out nuclear power by 2010, since that aspect of the problem had not been closely examined during the public debate preceding the referendum. Because of the importance the academy attaches to this subject, the Presiding Committee, IVA's top decision-making body, chose to undertake the planning and implementation of the study itself rather than appoint a special investigating committee. The study was completely financed by IVA funds.

The study assesses Sweden's present situation in terms of energy supply. In 1983, the installed capacity for electric production in Sweden included hydropower (15,078 MW), 12 nuclear power units (7718 MW), and conventional thermal power (8520 MW) for a total of 31,316 MW. Noting that Sweden is a country with a high energy demand because of its climate, long transport distances, and energy-intensive industry, Forsberg emphasizes that Sweden's dependence on imported raw materials for energy has become increasingly expensive. In 1971, the cost of Sweden's oil imports



Forsberg

amounted to 1.7% of its GNP; by 1982 the cost had risen to 7% of the GNP, despite the fact that oil imports had fallen by some 30% from 1971 levels. Oil still remains the most important raw material for energy for the heating and transport sectors.

Sweden's domestic energy resources are scarce: the country has no oil, gas, or coal deposits of any size. It does have large deposits of shale containing both uranium and hydrocarbons, but it can still import these resources more cheaply than it can extract them at home. More than half the country's production of electric power is based on domestic hydropower. "In the nation's established energy policy, the proportion of biofuels (wood, peat, straw, and reeds) is to have risen from the level of 2% in 1979 to 10% by 1990," Forsberg notes. Biofuels are limited by technology, however, and cannot be used as efficiently and as cheaply as coal, particularly in central station generation. The Swedish government is providing financial incentives to promote the use of biofuels. The paper and pulp industry, which constitutes a large portion of Sweden's industrial sector, uses biofuels (waste wood) for generating its own electricity, but doing so is not practical or feasible for other industries.

"Currently, the greatest share of electricity produced in Sweden comes from hydropower and nuclear power, which is why Sweden has one of the lowest prices for electricity anywhere in the world. And this low price also helps to make our industry competitive," Forsberg explains. The academy's study also took a detailed look at new energy technologies and how they can contribute to the energy supply. New technologies may play an increasingly important role in Sweden if the policy to phase out nuclear power remains in force.

Energy Technologies

In presenting its study, the academy took the approach that certain technologies will be of great importance to Sweden's future energy system, others will be of limited importance, and still others will be of no importance. It also assumed that the technologies of greatest importance would become both technically and commercially available in Sweden during the next 25 to 30 years.

For example, the heat pump market has grown rapidly in Sweden, and this technology, particularly ground-coupled heat pumps for residential use, will become increasingly important in the years to come. The academy also believes that new combustion technologies, such as fluidized beds, will have an impact on Sweden's future energy supply. "We are very encouraged by the advancements in fluidized beds, and Sweden has a large research program studying this technology. We already have fluidized-bed pilot plants, both atmospheric and pressurized, operating in Sweden," Forsberg notes. "We are also encouraged by the research into coal-water slurries and feel that they will be useful for combustion in small- and medium-sized plants. We do not, however, see any immediate use in Sweden for coal gasification or liquefaction."

Hydropower and nuclear power are the base of Sweden's electric power system, and as such, both technologies are of great importance to the nation. Expanding the use of hydropower is expected to bring about only marginal increases in the costs of electric power production. In the case of nuclear power, Sweden has anticipated the need to store waste and has devised a plan to keep spent fuel in interim storage for 40 years. After that time, the waste will be encapsulated in copper and buried about 500 meters underground.

Technologies of limited importance—geothermal, solar heating, wind energy, hydrogen gas, fuel cells, wave power, heat and electricity storage—are those unlikely to contribute significantly to Sweden's energy needs during the next 25 to 30 years. However, if the Swedish government decides to refrain from using already-established technology, they may become more important. "The use of wind and fuel cells may have some impact on our energy needs," Forsberg states. "We already have 2- and 3-MW wind machines in operation, and they perform very nicely, but the cost of the energy is prohibitive. We are very interested in fuel cell technology and will watch closely how it succeeds in Japan and the United States. But again, it will have to be a commercial technology before it will have impact on our needs."

Finally, the academy report dismissed as unimportant those technologies that will not be available commercially in the next 30 years or lack practical application in Sweden's climate. Its analysis of all these technologies concludes that hydropower and nuclear power, and electric power and heat cogenerated in combustion plants, will dominate the Swedish energy supply for the next 30 years. "It is becoming increasingly obvious to many of us outside the government that it will be impossible to replace both oil and nuclear power with domestic sources of energy in an economically successful way," Forsberg emphasizes.

Scenarios, Conclusions, and Recommendations

The Future Energy System study provides four scenarios that depict what the energy and economic system in Sweden will look like in 2010 if various supply paths are taken. Scenario A envisions a continued use of nuclear power and a 12 million MWh (e) expansion of hydropower, to 78 million MWh (e). Scenario B supposes a continued use of nuclear power as well, but with no expansion of hydropower. The third scenario, C, calls for a phasing out of nuclear power but provides for a hydropower expansion of 12 million MWh (e). And finally, scenario D supposes a phasing out of nuclear power with no expansion of hydropower beyond an already-set limit of 66 million MWh (e).

"In all these scenarios," reads the study, "it has been assumed that economic reasons will dictate the development of the energy system within the framework of the requirements formulated by society—with regard to environment, health, and security of supply." The effect of each scenario on the cost of electric power production and the potential increase in this cost have been calculated on the basis of a high industrial growth rate (3.5% a year) and with the expectation that all industries will increase their electricity consumption through 2010. Consumption of electric power in Sweden in 1982 was 90.2 million MWh (e); depending on which scenario is used, the study projects an increase in consumption by the year 2010 to between 130 and 140 million MWh (e).

For example, if nuclear power were permitted after the year 2010 and if hydropower expansion could not exceed 66 million MWh (e) (scenario B), Sweden's entire combined heat and power potential would have to be used initially to make up the shortfall. Later, it would be most economical to invest in new nuclear power plants, which would produce an estimated total of 3 million MWh (e), or to import electric power.

If the use of nuclear power were to continue and if hydropower were expanded to a total of 78 million MWh (e) (scenario A), part of the combined heat and power potential could be used to satisfy Sweden's electric power requirements in the year 2011. Under these circumstances, expanding nuclear power would not be an economically viable proposition. The academy's study also points out that the lead time for building a power plant in Sweden is 6 to 10 years. Thus, if the costs of future electric power production are to be minimized, the government will have to decide within a few years whether to expand the country's hydropower potential.

On the basis of these two scenarios, which assume a continued use of nuclear power and—consequently—low electric power prices, the annual need for electric power in the year 2010 is projected to be 140 million MWh (e). On the other hand, if (as in scenario D) nuclear power were to be phased out and hydropower not permitted to expand beyond the set limit of 66 million MWh (e), an additional 10 million MWh (e) would have to be produced in coal-fired power plants (plants that produce only electric power) by 2010. To cope with the transition, the government would have to make a decision on coal-fired power as early as the end of the 1990s, since these plants would have to be ready for trial operation before the year 2011.

Although it would be technically feasible to supply Sweden with electric power even in the event that nuclear power were phased out in 2010, the report notes that the economic consequences, with regard to both investments and annual operations costs, would be very considerable. Estimates indicate that, compared with today's costs, there would be a 50–55% real increase in the average cost of producing electric power. Sweden would then have substantially higher energy costs than many other industrial nations who continue to use nuclear energy. This differential would have a negative effect on Sweden's ability to compete on the international market, and the corresponding drop in demand for electric power—from an estimated 140 million MWh (e) to around 130 million MWh (e)—would hurt the country's industrial growth and employment.

"What the academy discovered is actually very simple," Forsberg says. "In the event that nuclear power is phased out, additional electric power production at very high cost could be obtained from coal-fired power plants and, possibly, though we don't know yet, through fuel cell technology. And we will have to import a great deal of coal to meet the demand.

"Of course, because of environmental concerns, there is also some resistance to building new coal plants in Sweden," notes Forsberg. "If we also decide, for environmental reasons, to impose a restriction on the total use of coal, the situation will become precarious. It is impossible to produce electric power with biofuels to the extent that would be necessary. Therefore, we would have to return to importing oil and natural gas or reduce steeply the use of electric power. A development of this kind jeopardizes the total use of resources by society and can lead to a pronounced deterioration in the standard of living in Sweden," he cautions.

The study emphasizes that, in all probability, the 12 nuclear power reactors that are already or soon to be commissioned will be operated profitably and safely far into the next century. It recommends that these plants be used as long as they satisfy the current environmental, health, and safety regulations and can be operated economically. To phase out nuclear power in the year 2010 is therefore technically unjustified and, moreover, indefensible from the standpoint of the national economy, the academy argues. There are telling factual reasons to call for reconsideration of the parliamentary decision to phase out nuclear power.

Hans Forsberg agrees wholeheartedly: "Now, in our study we are not recommending the building of any new nuclear units; we are simply suggesting that the government remove the date for shutting down the existing units and that the plants be allowed to run as long as is economically feasible. Our children, who may be wiser than we, should have the opportunity to decide whether the country needs nuclear power to remain internationally competitive."

A copy of the academy's study is available from the Royal Swedish Academy of Engineering Sciences, P.O. Box 5073, S-102 42, Stockholm, Sweden. ■

This article was written by Christine Lawrence, Washington Office.

Coal Is Still Key to China's Energy Future

Coal experts from the People's Republic of China visit EPRI and, in a wide-ranging discussion, talk about China's coal policies and emerging environmental issues.

EPRI's Advanced Power Systems Division hosted a week-long visit by Dr. Bozen Sun and Dr. Yin Ren Wang, both vice chairmen of the Beijing Energy Society. Dr. Sun heads the Chinese Academy of Science's Research Institute of Environmental Chemistry, and Dr. Wang directs China's Institute of Coal Chemistry.

While at EPRI, the visitors held an informal exchange with members of the technical staff, answering questions on topics ranging from energy policy in China and the present and future status of Chinese coal to acidic deposition and the control of particulate matter, SO_x, and NO_x.

Despite large offshore oil fields and an abundance of rivers for hydro development, China's dominant energy source is still coal, with reserves currently set at over 600 billion tons. China burns more than 500 million tons annually, according to Dr. Sun, and this represents 70% of the country's total energy consumption. Until fairly recently coal was burned with little regard to its environmental effects, and the result was high concentrations of suspended particulates, especially in winter in the northern cities.

Explaining that there is no agency in the People's Republic dedicated to environmental protection per se, Dr. Sun said that China's policy makers are now showing heightened sensitivity to environmental concerns, largely as a result of national policy decisions to increase China's GNP and, hence, its energy consumption. Because these decisions are likely to increase pollution if some abatement measures are not taken, there has been increased interest in setting standards for power plant emissions, constructing more gasification plants, reclassifying China's vast coal reserves according to their sulfur and nitrogen content, and learning more about the physical and chemical makeup of various coals.

Another outgrowth of this awakening environmental concern, Drs. Sun and Wang agreed, has been a focus on acid rain. Early data from a nationwide survey undertaken by the government in 1982 suggest that the phenomenon is fairly localized, in spite of the vastness of the Chinese land mass, and occurs mainly in the southwestern provinces of Szechwan and Keichow.

Coal mined there generally has a higher sulfur content than that mined in the north. These southern regions have been open to intense coal mining only during the past decade and still lack the extensive rail network needed to move their coal to market. Consequently, they burn a large portion of their high-sulfur coal close to its source. This practice appears to have resulted in higher levels of acidic deposition, levels that have made visible inroads on the region's forests and mountainside foliage.

Asked about other kinds of air pollution, Dr. Wang acknowledged that urban air pollution is another problem confronting China's policy makers. In fact, he noted, the city of Beijing—in an attempt to ameliorate air quality—has initiated a campaign urging its citizens to cease burning the traditional charcoal briquets in their home stoves and instead use cleaner-burning, higher-Btu natural gas for cooking and heating.

Despite the fact that China ranks third in the world in coal reserves and production (behind the Soviet Union and the United States), its energy consumption per capita is well below that of industrialized nations. This circumstance has potentially serious consequences for China's economic development.

The response by China's policy makers, the visitors explained, has been to call for a more rational coal policy—one that would improve management, reduce waste, channel appropriate resources to the proper markets, and redress the imbalances in supply and demand. This goal has meant, among other things, constructing more coal bases, especially in the energy-poorer southern provinces; improving product quality; and pressing for more coal science R&D. As a result, more open-pit mining is being encouraged, as is a greater mechanization of mining practices.

Special attention is also being paid to generating power at the pitheads and to building coal gasification plants using a variety of technologies. Following EPRI's lead, China is constructing two plants based on the Texaco gasification process. One will provide hydrogen for an existing ammonia plant; the other will generate electricity and coproduce methanol along with clean gaseous fuel.

What China is now looking for, according to Dr. Sun, is an overall plan to bring the country to its fullest energy potential. Although the fulfillment of this potential will include nuclear power and will certainly entail an increased use of oil, natural gas, and hydro, China's main energy source will continue to be coal for many years to come. To use this vast resource prudently and economically—to bring about what Dr. Wang calls a "balanced, energy-related environment"—is China's great challenge. ■

Major Effort Launched to Study Acid Rain Effects on Forests

EPRI has recently launched a four-year, $8 million project to study the effects of acidic deposition on the health of U.S. forests. The biggest and most comprehensive project ever undertaken by EPRI's Ecological Studies Program, it is also the largest privately funded acidic deposition study in the United States. The Empire State Electric Energy Research Corp. and the New York State Energy Research and Development Authority are cofunding the study with EPRI.

"The health of forests and the impact of acidic deposition constitute one of the most active aspects of the environmental pollution debate," states John Huckabee, manager of the Ecological Studies Program. "In this study, we seek the necessary scientific understanding of the factors and the interactions behind forest decline."

Several hypotheses have been advanced to explain dying trees and the decline of some forests: acidic deposition; the effects of aluminum, ozone, and nitrogen; and natural causes. This study marks the first time, however, that researchers will attempt to document mathematically how acidic deposition, the tree canopy (or treetops), and soil processes are linked to a forest's nutrient status, which in turn affects forest productivity.

Working under EPRI contract, an environmental team from Oak Ridge National Laboratory will manage and coordinate researchers from the universities of Georgia, Michigan, Pennsylvania, and Washington; the State University of New York at Albany; the U.S. Forest Service; and the National Park Service.

In addition to conducting field studies at nine forest sites in New York, North Carolina, Tennessee, and Washington, the researchers will build on data developed by EPA and EPRI in their studies of aluminum biogeochemistry and integrated lake-watershed acidification. These studies had several forest sites in common.

Also aiding the work will be reports from the German-American Exchange for Forest Decline, an ad hoc expert scientific committee formed in 1984 by EPA and agencies of the Federal Republic of Germany. A phenomenon called *waldsterben*—the death of mature trees, coupled with the failure of young trees to replace them—was first observed in Germany and has been the focus of much research there. Several tree species have been affected in Europe, while only red spruce appears to have suffered in this country. Researchers in Canada and Europe may join the EPRI project and expand the project to additional sites in the near future. ■

Cooling-Tower Tests Begin in Houston

Reducing the cost of generating electric power through better cooling-tower design and operation is the goal of tests now under way at the Cooling Tower Performance Test Facility near Houston, Texas. The $1 million EPRI facility, located at Houston Lighting & Power Co.'s Parish generating station, began operations in May and will help utilities reduce costs by developing methods to improve the design of new evaporative cooling towers, the analysis of vendor bids, and the retrofitting of existing towers.

The research being conducted at this first-of-its-kind facility includes testing various types of cooling-tower fill (or packing), using computer codes to predict cooling-tower behavior under various conditions, and verifying the newly developed predictions on full-sized towers. A design manual for electric utilities will be developed on the basis of the results of these tests. "An increase of 5% in cooling-tower efficiency will result in a savings of about $10 million over the 40-year life of a 1000-MW plant," says EPRI project manager John Bartz.

The Cooling Tower Performance Test Facility is part of a $3 million project to help utilities purchase cooling towers that will operate more efficiently and to help them bring existing towers up to state-of-the-art standards. The facility was built by EPRI and a consortium of eight utilities in late 1984. The sponsoring utilities are Houston Lighting & Power Co., Indianapolis Power & Light Co., Pacific Gas and Electric Co., Public Service Co. of Oklahoma, the Salt River Project, Southern California Edison Co., Southern Company Services, Inc., and the Tennessee Valley Authority. ■

Workshops Offer Information on Nuclear Plant Savings

Two EPRI workshops that examined ways to stem the rising costs of constructing and modifying nuclear power plants have provided planning guidance for the Institute's research. Conducted earlier this year at EPRI's Nondestructive Evaluation Center in Charlotte, North Carolina, the workshops attracted industry experts in nuclear plant piping design, fabrication, and installation and in electrical and instrumentation construction.

Participants at the piping workshop proposed five broad measures that, if implemented, could have a dramatic impact on reducing piping costs: stabilizing the application of regulations and design changes during construction, reducing paperwork and field changes, optimizing quality assurance and quality control (QA/QC) procedures, reducing pipe support hardware, and applying computer-aided construction (CAC) techniques.

The piping workshop participants went on to identify specific actions for implementing such measures. In fact, professional and code committees are already taking steps to relax load-combination criteria and installation tolerances, to use increased damping in piping analysis, to eliminate the rigorous requirements stipulated in the ASME Boiler and Pressure Vessel Code (Section III, Subsection NF), and to revise weld inspection criteria. Furthermore, an EPRI study by Duke Power Co. (RP2514-3) is developing guidelines for computer-aided engineering applications that include CAC.

The cost-savings suggestions offered by participants in the electrical and instrumentation workshop also focused on improvements in QA/QC practices and CAC. Specifically, they recommended replacing metal conduit with lighter-weight, more easily handled material; improving the design of raceway support systems; and studying nuclear plant applications of such advanced technologies as fiber optics (to reduce the number of electrical cables) and time-domain reflectometry (to perform construction verification and surveillance testing).

The recommendations provided by these workshops are being used in formulating EPRI's research strategy for the Nuclear Power Division's Maintainability and Constructability Program. To help implement the new research, Victor Vanderzyl, a construction expert, is on loan from Bechtel Power Corp. as a project manager. ■

PCB Removal Process to Get Georgia Test

A new process to remove PCBs (polychlorinated biphenyls) from electric utility transformer oil will soon be demonstrated for the first time as a result of a recent agreement between EPRI and Georgia Power Co. The new technology, developed under EPRI contract by Veridyne and General Electric Co., improves the economics of the destruction process by extracting the PCB in a concentrated form.

EPRI began its PCB extraction research in 1981 and has spent about $800,000 on it to date. This year-long demonstration—set to begin in early 1986—is expected to cost an additional $800,000, with Georgia Power spending about $700,000 for the process facility and EPRI contributing about $100,000 in engineering expertise.

During the extraction process, a solvent (methyl carbitol) and the contaminated mineral oil are forcibly mixed and repeatedly agitated and allowed to settle. The solvent extracts PCB from the oil during each cycle, eventually removing most of it. The clean oil is washed to remove the solvent and is treated for reuse with normal utility oil cleanup equipment.

A distilling of the PCB-containing methyl carbitol boils off most of the solvent, which can be recovered for reuse in the extraction process. Left behind is a mixture of PCB, mineral oil, and solvent that is cooled and further separated to yield a residue of mineral oil containing about 5% PCB and a small quantity of lost solvent. This residue, which makes up about 1% of the initial contaminated oil feed, must then be sent to a certified incinerator for disposal.

Georgia Power will use the extraction facility to clean oil from its own transformers and will perform the service for those utilities it has traditionally supchromatographic analysis and allows self-calibration by periodically analyzing "standard" samples of known composition. ■ *EPRI Contact: Thomas Passell (415) 855-2070*

NDE Image Enhancement Saves Georgia Power $1 Million

An in-service inspection of a reactor feedwater pipe in the Hatch-2 nuclear unit of Georgia Power Co. (GPC) indicated possible cracking and signaled a potentially costly repair/replacement program. Quickly initiating a multiphased effort to analyze and correct the problem, GPC and Southern Company Services, Inc., assembled a cadre of experts that included personnel from EPRI, Southwest Research Institute, and Schonberg Radiation, Inc. Using Minac/Shrinkac, the group reviewed preservice NDE radiographs and those acquired during the inspection. EPRI worked with Schonberg Radiation to apply EPRI's computerized-image data processing method to enhance the radiographic images for comparison. "The technique," Jim Edwards and Len Gucwa of GPC agree, "showed that we did not have a pipe/nozzle crack problem." Able to assure the NRC there was no problem, GPC was spared the expense of repairing its reactor vessel nozzle and saved an estimated $1 million in replacement hardware. ■ *EPRI Contact: Mel Lapides (415) 855-2063*

New Monitoring System at SCE Checks Torsional Oscillation

After electrical disturbances on a transmission network caused severe damage to generator shafts at the Mohave Generating Station operated by Southern California Edison Co. (SCE), the utility adopted operating and transmission changes to reduce the likelihood of future damage. In order to verify that the new operating conditions were adequate, however, SCE needed a means of monitoring electrical disturbances and correlating such data to torsional oscillations in generator shafts. Similar problems nationwide had prompted EPRI to fund General Electric Co. to develop a predictive analytic model of such occurrences, as well as a monitoring system. The prototype of the monitoring system was installed at SCE's Mohave plant. Now, when torsional oscillation occurs in a generator, the monitoring system will provide some of the information needed to determine whether a shaft inspection is necessary. The system will also help in scheduling repairs and determining if a shaft should be replaced. The potential savings from the monitoring system would result from SCE's avoiding costly ($2.8 million) shaft inspections and being able to replace turbine shafts before catastrophic failure occurs. ■ *EPRI Contact: James Edmonds (415) 855-2291*

SACTI Model Plots Plume Dispersion for Virginia Power

To meet the siting and licensing requirements for building new power plants, utilities must evaluate the environmental effects of such construction, a process that requires complex computer programs. Virginia Power allocates in-house resources to perform regulatory-required air quality modeling analyses and, as part of this assessment, has searched for a readily usable, generic cooling-tower plume prediction model. Fortunately for Virginia Power, the utility industry now has such a tool: the seasonal and annual cooling-tower impacts model. Known as SACTI, it is an updated version of plume dispersion and drift deposition models developed earlier for EPRI by Argonne National Laboratory and the University of Illinois. In contrast to the earlier models, SACTI accounts for seasonal and annual weather variations, deals with a variety of terrains, and can predict a number of plume dispersion variables. Using SACTI, Virginia Power estimates it may realize a one-time savings of $200,000 and predicts future savings of $10,000 to $20,000 for each SACTI application. ■ *EPRI Contact: John Bartz (415) 855-2851*

Electric ARM Hands Pacific Power $1100 Savings per Household

Flexible, convenient, and inexpensive, the Electric ARM (appliance research metering) system developed for EPRI by Robinton Products, Inc., continues to perform well for utilities, collecting end-use load data on household electric appliances. Requiring no rewiring, ARM can measure various appliance loads in one or more households, and its ease of installation lowers costs and increases sample reliability by improving customer acceptance. A remote unit at each monitored appliance sends coded data via the house wiring to the receiver, which outputs pulses for subsequent recording. Recently, a temperature probe and also a pulse transponder that can accommodate standard pulse-initiating meters were added to the ARM product line. As the first large user of the Electric ARM, Pacific Power and Light Co. estimates that ARM has saved it $1100 per household over and above the cost of hard wiring to monitor power consumption history. Since ARM was introduced in 1982, nearly two dozen utilities have installed several thousand of the units, which are proving to be extremely reliable. Recent applications have included room air conditioners and commercial HVAC and lighting. ■ *Contact: Robinton Products, Inc. (408) 738-8330; EPRI Contact: Edward Beardsworth (415) 855-2740*

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

AMORPHOUS SILICON FOR THIN-FILM PV DEVICES

Thin-film photovoltaic (PV) devices for utility bulk power applications offer two manufacturing advantages: material consumption is optimized, and the large-area deposition processes used to produce thin films lend themselves to automation. After a wide-ranging review of the state of the art of PV technology conducted by EPRI in 1982–1983 (AP-3351), amorphous silicon used in multilayer configurations was identified as the leading thin-film candidate for utility bulk power generation. The potential of amorphous silicon for use in alternative cell designs and with various alloying materials makes it a good prospect for meeting utility bulk power cost and performance targets for flat-plate modules, nominally \$100/m² and 15% efficiency. Moreover, the worldwide interest in amorphous silicon for electronic semiconductor applications increases the probability that significant technical advancement in this area will continue. EPRI's amorphous silicon research seeks to further this advancement through university-based efforts aimed at increasing the fundamental understanding of key issues in technology development.

Research on amorphous silicon materials and devices has been proceeding for over a decade with corporate and government support, and the participants have evolved into a truly international community. In terms of conversion efficiencies, this research has achieved the following: 11–11.5% for single-junction laboratory-scale solar cells (1 cm^2); about 5% for commercially available power modules (1000 cm^2), first introduced in late 1984; and 9% for large-area preproduction power modules (100 cm^2).

The efficiency of single-junction laboratory devices is rapidly approaching the practical achievable limit of 12–14%. Laboratory research on multijunction (two- and three-junction) solar cells, also called tandem cells, has produced small-area (1-cm^2) cells that are 12% efficient. The multijunction approach is promising because it allows a single unit to make use of wavelengths normally associated with several different kinds of cells (Figure 1). The efficiency limit for multijunction devices has not been well defined, but it appears that they may be able to achieve the 18% efficiency required for 15% efficient power modules.

The research during the last 10 years has provided some understanding of amorphous materials and has led to progress in PV device fabrication. For this progress to continue, it is necessary to increase our fundamental understanding of both materials and devices. Toward that end EPRI initiated an amorphous silicon research program about 18 months ago. The program was designed with input from an industrial advisory committee, which helped to formulate the objectives and to review the proposals of university contractors. Composed of leading research scientists and engineers from the U.S. amorphous PV industry, the committee continues to serve in a technical review capacity.

Together with key EPRI-sponsored university contractors, the advisory committee has identified four areas where increased understanding is vital to the continued development of amorphous silicon thin-film devices. These are (1) high-quality, low-band-gap amorphous silicon alloy materials, (2) the kinetics of deposition and film growth, (3) the physics of amor-

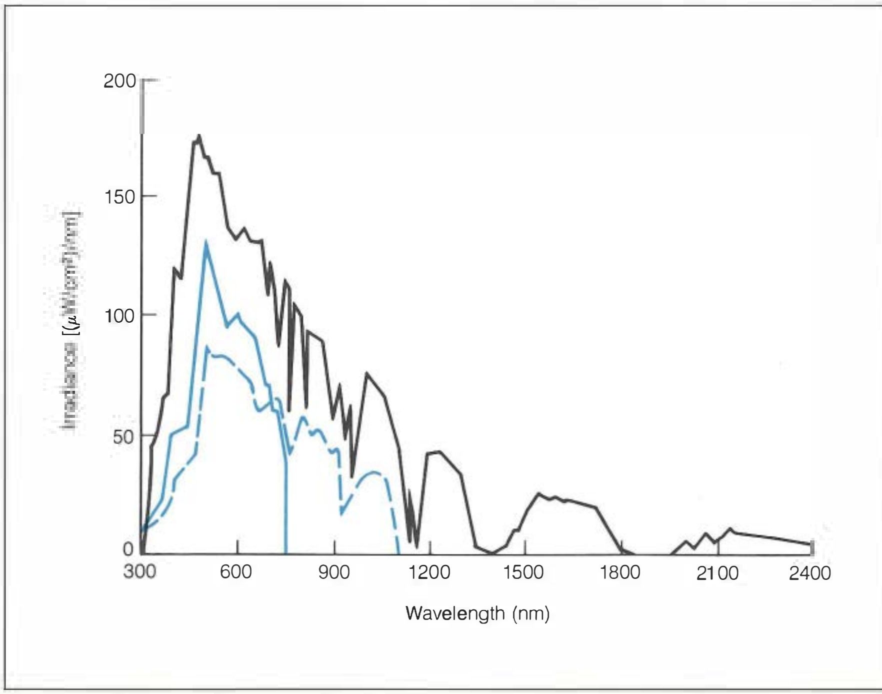


Figure 1 Because each layer in a multijunction PV cell is treated to optimize energy conversion in a selected band of the wavelength spectrum, such cells can convert a larger fraction of solar energy to electricity than can single-junction cells. The black curve shows the total solar radiation as distributed across the spectrum; the colored curves correspond to two layers of a multijunction cell.

phous silicon thin-film devices, and (4) long-term cell stability. The groups participating in the EPRI effort have structured their research around these critical issues.

At Princeton University work is under way to address the issue of low-band-gap amorphous silicon alloys (RP1193-6). The process being used to deposit the alloy material in thin films is either dc or radio-frequency plasma-enhanced chemical vapor deposition (PECVD), also known as glow discharge decomposition. The emphasis is on careful materials preparation, consistent with the current state-of-the-art understanding. Consequently, the research reactors include vacuum interlocks for sample introduction, mass flow controllers for the gas injection system, turbomolecular pumps to reduce contamination, and diagnostic equipment for maintaining chamber operating conditions and purity (Figure 2).

The alloy material under investigation by the Princeton group is amorphous silicon-germanium (a-SiGe:H). Amorphous silicon (a-Si:H) has an optical band gap of approximately 1.7–1.8 eV. Alloying it with germanium can reduce the band gap to less than 1.0 eV. The challenge is to lower the optical band gap of the alloy while maintaining the desirable electronic properties of amorphous silicon. To date, it has not been possible to maintain these properties in alloys with band gaps below 1.4–1.5 eV. In the short time the Princeton researchers have been working, they have succeeded in depositing amorphous silicon-germanium alloys with band gaps from 1.0 eV (0.85% germanium) to 1.65 eV; mixtures of SiF_4, GeF_4, and H_2 are used to control the alloy composition. However, the researchers have also seen a degradation of electronic properties in the alloys with band gaps below 1.5 eV.

The importance of the second area recommended for research attention, deposition kinetics and film growth, is reflected in this fact: for thin-film photovoltaics to become an option for bulk electric power generation, it will be necessary to design and build deposition machines capable of producing some 10 million ft^2 (929,000 m^2) of solar cells a year. This represents a large improvement over today's technology. To scale up to the level required means increasing both the area over which uniform films can be deposited and the rate at which they can be deposited. Important questions to be investigated concern the decomposition kinetics of source gases used in the deposition process and the effect that energetic particle bombardment of the growing film surface has on the material's electronic properties. Two contractors are addressing these questions.

One approach to depositing amorphous silicon is to thermally decompose the source gas and deposit the resulting radical species onto a substrate. This method is known as chemical vapor deposition, or CVD. Because a thermal source is used to decompose the gas, there is no bombardment of the growing film surface with energetic particles. A group of researchers at Poly Solar, Inc., is applying this method in an effort to better understand the fundamental properties of amorphous silicon (RP1193-2).

The investigators have found that the film growth rates are too slow when using silane (SiH_4) as the source gas because of the low temperature at which the substrate must be maintained. Using disilane (Si_2H_6), however, enables a much higher deposition rate at the same temperature and produces films with high-quality electronic properties. The films deposited by Poly Solar have been of such good quality that the group has begun a detailed study of another key issue, film stability. The CVD films deposited thus far display an experimentally controllable instability response when exposed to light. A greater understanding of this phenomenon is needed in order to produce high-efficiency, long-lifetime devices.

A second way to address the kinetics of deposition and film growth is to independently control a greater number of the deposition parameters. Thus, instead of avoiding energetic particle bombardment of the growing film surface, one might attempt to control in a reproducible and measurable fashion the flux and energy of particles arriving at the film surface. This is the thrust of work at the University of Illinois (RP1193-7), where researchers are using reactive magnetron sputtering in order to observe and model the deposition and growth process.

Reactive sputtering is a technique whereby a reactive gas (in this case, hydrogen) is introduced into the deposition chamber along with

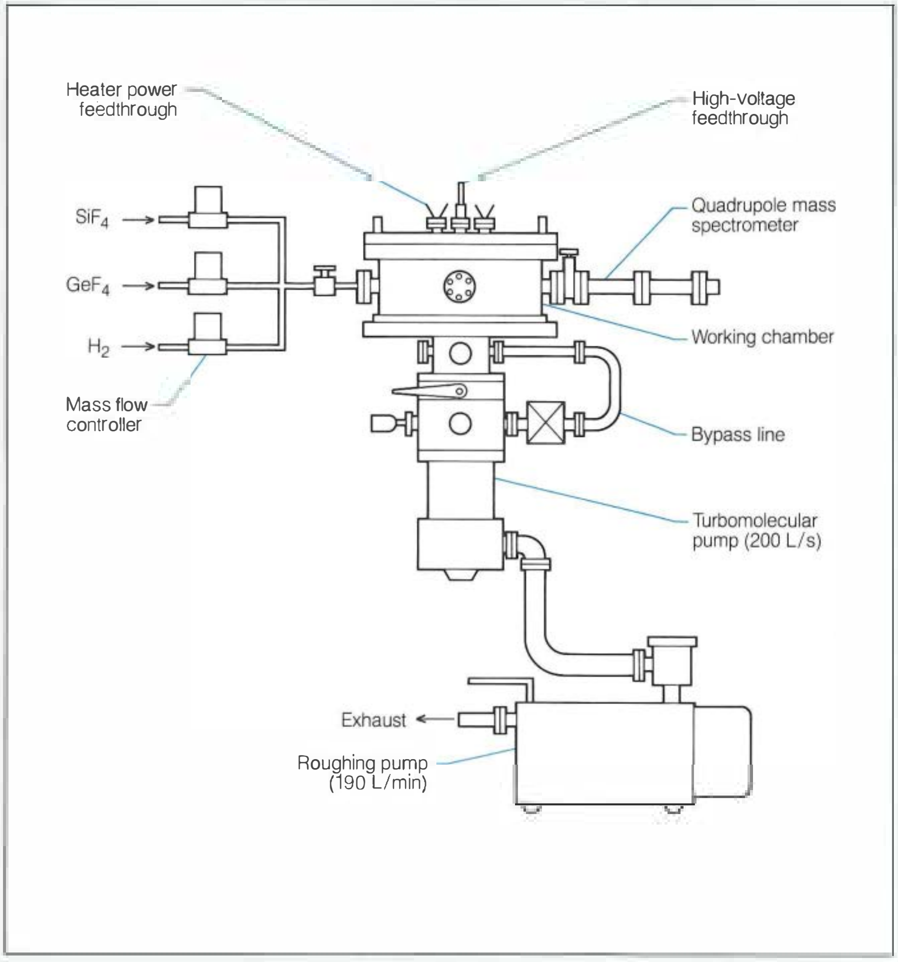


Figure 2 This vacuum system is being used for the deposition of amorphous silicon alloys in EPRI-sponsored research on thin-film photovoltaics at Princeton University. Extensive monitoring and control equipment is incorporated to ensure correct materials preparation.

the argon sputtering gas so that a chemical reaction takes place at either the substrate or the cathode, depending on the deposition parameters. In this way an amorphous silicon thin film can be produced from a pure silicon target by sputtering. In magnetron sputtering a dc magnetic field is used to confine the plasma discharge to a region near the target, and energetic particle bombardment is applied separately to the growing film by means of Kaufman ion sources. The deposition chamber is specially equipped with a modulated-beam optical spectrometer and a quadrupole mass analyzer to detect and identify the radical species arriving at the growing film surface.

To further the understanding of PV device physics, a group from Pennsylvania State University is developing models of single-junction and multijunction devices (RP1193-8). These analytic models are intended to provide meaningful correlations between PV device characteristics and measurable materials parameters. They will serve as road maps to enable the groups working on materials development to optimize thin films without fabricating complete devices.

EPRI's amorphous silicon research program has been undertaken with the recognition that a long-term commitment to understanding the fundamentals of the technology is required before the PV industry will be able to supply thin-film solar cells for bulk power generation. An important part of this research is the fostering of cooperation among interested university and industrial research groups in order to optimize the application of available resources and minimize development time. *Project Manager: John L. Crowley*

PERFORMANCE OF UTAH BITUMINOUS COAL IN A MOVING-BED GASIFIER

The U.S. electric utility industry has recently shown interest in the use of relatively small—25 to 75 MW (e)—power plants fueled with clean synthetic gas derived from coal. A coal gasification system receiving considerable attention for the production of low-Btu fuel gas for such plants is the Wellman-Galusha system. It features a commercially proven, moving-bed-type gasifier that operates at ambient pressure and uses air as the oxidant source. In August 1984 EPRI and Utah Power & Light Co. (UP&L) partially funded a test of a Utah bituminous coal in a 6.5-ft-diam (2-m) Wellman-Galusha gasifier at the U.S. Bureau of Mines' Twin Cities Research Center in Minneapolis. The coal's performance was excellent: the dry product gas had a higher heating value of 170–180 Btu/scf, and high-quality coal liquids were produced at a rate of over 35 gal (132 L) per ton of coal. The overall gasification efficiency (based on the production of hot raw fuel gas) exceeded 92%; the gasification efficiency based on cold detarred gas (but including the tar/oil energy) was 85%.

A number of U.S. electric utilities are interested in using relatively small power plants to meet a portion of their load growth requirements. Currently, UP&L is investigating the feasibility of producing electricity from small power plants fueled with a high-volatile, low-sulfur bituminous coal from the Blind Canyon seam in Utah. One of the options under consideration is to produce power by firing dual-fuel diesel engines with coal-derived synthetic gas and tars produced in a moving-bed gasifier.

Under RP2656-1 EPRI recently helped fund a program to test the performance of UP&L's Blind Canyon coal in a Wellman-Galusha moving-bed gasifier at the Twin Cities Research Center in Minneapolis. The major objectives of the test program were (1) to obtain design-point gasification data (e.g., maximum coal throughput, product gas composition, gasifier thermal efficiency) for the Utah coal, and (2) to determine the characteristics (e.g., heating value, composition, sulfur content) of the tars produced during the gasification process.

Test facility

The gasification test facility at the Twin Cities Research Center is operated by Black, Sivalls & Bryson, Inc. (BS&B), under contract with the Bureau of Mines, with major funding from DOE. Since 1977, it has been used extensively to evaluate the gasification characteristics of a wide variety of U.S. coals in a moving-bed gasifier. Direction for the test program has been provided by the Mining and Industrial Fuel Gas Group (MIFGA), an industry support group of which EPRI is a member.

The test facility consists of a coal storage and handling system to process, deliver, and meter sized coal to the gasifier; a Wellman-Galusha gasifier with an inside diameter of 6.5 ft (2 m) and a gas production rating of 30 million Btu/h; a refractory-lined cyclone to remove dust in the product gas; an air blower; a product gas handling and combustion system; and a flue gas scrubber-fan-stack system to remove sulfur dioxide and particulates from the products of gas combustion.

The test facility is equipped with standard industrial monitoring equipment for the measurement of temperatures, pressures, flows, and process conditions. An automatic data acquisition system records these measurements for subsequent process analysis. The University of Minnesota's Particle Technology Laboratory, under subcontract to BS&B, monitors process parameters and provides analyses for all material inputs and outputs.

The facility also has a 0.2-scfm (0.094-L/s) slipstream gas sampling and conditioning system to detar and dry the product gas before analysis by gas chromatography. This system, which consists of a surface contact condenser and an electrostatic precipitator operating in series, was designed by the Particle Technology Laboratory. In addition to providing clean gas for analysis, it measures gasifier tar production and collects modest tar quantities for analysis.

In order to collect larger quantities of the Utah coal tar product for characterization studies, EPRI contracted with BS&B and the Particle Technology Laboratory to design, construct, and operate an enlarged (10 scfm; 4.7 L/s) gas sampling and conditioning system. This system, which is based on the design of the smaller train, operated successfully during the Utah coal test program and collected over 350 lb, or 42 gal (159 kg, or 159 L), of relatively dry high-quality tar.

Wellman-Galusha gasifier

In the past century over 10,000 coal gasifiers of the moving-bed type have been used to produce clean fuel gas, primarily for industrial applications. Moving-bed gasifiers, often called fixed-bed gasifiers in the literature, are inherently simple and reliable and have a relatively high thermal efficiency. However, in general they are confined to handling graded coals in the size range of ¼–2 inches, yield tars and oils as by-products, and require special provisions, such as an agitator, to handle caking (agglomerating) coals.

The Wellman-Galusha gasifier is a single-stage, moving-bed, atmospheric pressure system that has been in commercial use throughout the world for over 30 years. Figure 3 presents a process schematic of the Wellman-Galusha installed at the Twin Cities Research Center. Since the gasifier uses air as a source of oxygen, it produces gas with a low Btu content and a higher heating value in the range of 120–180 Btu/scf. It has a gravity coal feed system, a water-cooled agitator, and a rotating, eccentric, step-type grate for ash removal. The retort is water-jacketed and has no refractory lining. The input air flows across the surface of the hot water at the top of the jacket and becomes saturated with steam before injection under the ash grate.

The coal feedstock enters the Wellman-Galusha at the top of the gasifier and moves in countercurrent flow to the ascending gas products (or blast). As the coal descends, it undergoes drying, devolatilization (liberating tars, oils, and some light hydrocarbon gases),

Figure 3 Wellman-Galusha moving-bed gasifier and cyclone. In tests with a Utah bituminous coal, this 6.5-ft-diam (2-m) gasifier yielded a product gas with a higher heating value between 170 and 180 Btu/scf and coal liquids of high quality.

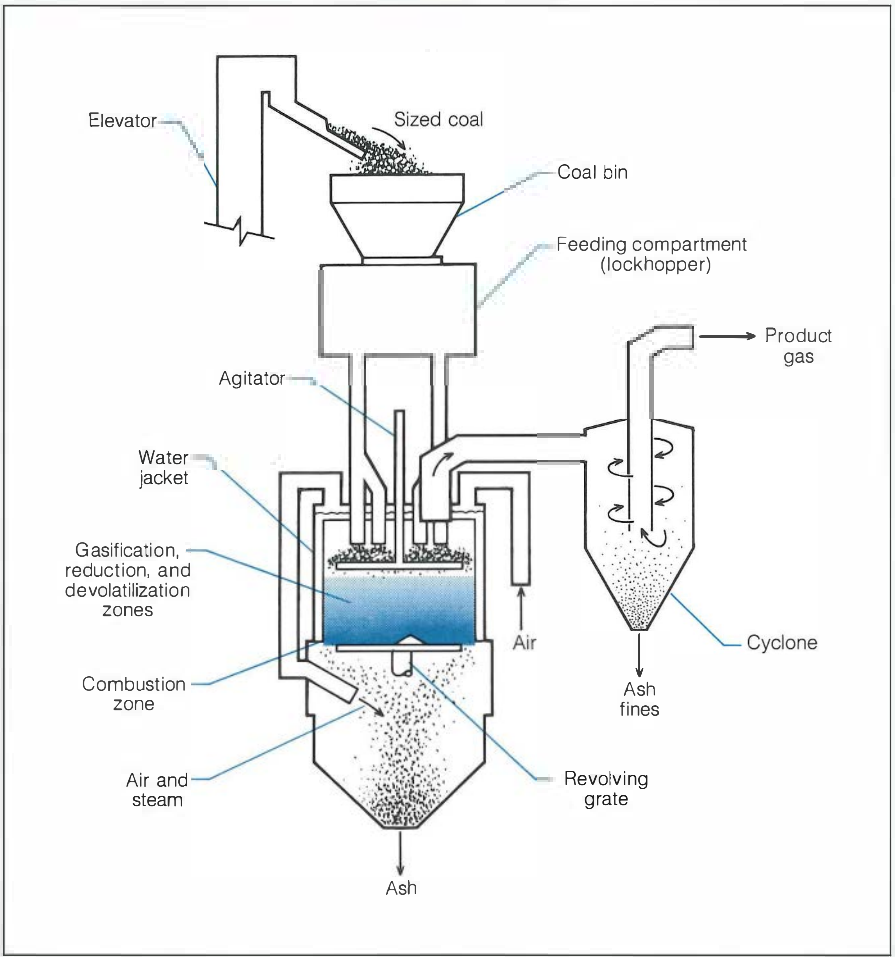


Table 1
ANALYSIS OF UTAH TEST COAL

Proximate analysis (wt%)	
Volatile matter	38.92
Fixed carbon	43.88
Ash	11.10
Moisture	6.10
Ultimate analysis (wt%)	
Carbon	66.52
Hydrogen	5.09
Nitrogen	0.96
Sulfur	0.52
Oxygen (by difference)	9.71
Ash	11.10
Moisture	6.10
Higher heating value, as-received coal (Btu/lb)	11,926
Ash fusion temperatures (°F)*	
Initial deformation	2345; 2250
Softening	2450; 2370
Hemispherical	2490; 2450
Fluid	2660; 2495
Free-swelling index	1.5

*The first value in each case is the temperature under oxidizing conditions; the second, under reducing conditions.

Table 2
DESIGN-POINT GASIFICATION DATA

Coal throughput, as received (t/h)	1.80
Blast saturation temperature (°F)	145
Air/coal ratio (lb/lb)	2.11
Steam/coal ratio (lb/lb)	0.388
Dry gas/coal ratio (scf/lb)	53.4
Dry gas composition	
Hydrogen (vol%)	18.5
Carbon monoxide (vol%)	26.9
Methane (vol%)	1.85
Ethane (vol%)	0.191
Ethylene (vol%)	0.143
Propane (vol%)	0.010
Propylene (vol%)	0.061
Carbon dioxide (vol%)	6.25
Nitrogen (vol%)	45.3
Hydrogen sulfide (ppm, by vol)	1076
Carbonyl sulfide (ppm, by vol)	158
Dry gas higher heating value (Btu/scf)	173
Dry gas lower heating value (Btu/scf)	161
Dry tar yield (lb/100 lb coal)	14.4
Dry tar higher heating value (Btu/lb)	16,200
Dry tar sulfur content (wt%)	0.29
Thermal efficiency (%)	
Hot raw gas	93.5
Cold gas with tar	84.6
Cold gas without tar	66.1

Note: Except for throughput, all coal values are for dry, ash-free coal.

and gasification until it reaches the combustion zone, where it is nearly completely consumed to leave an incombustible ash residue. This residue is discharged through the rotating grate as a dry, granular solid.

In the combustion zone, oxygen in the air reacts with carbon to form carbon dioxide (CO_2) and release heat. In the gasification zone, some of the steam and carbon react to form combustible carbon monoxide (CO) and hydrogen (H_2) while absorbing the liberated heat. At the same time, some of the CO_2 formed earlier reacts with carbon to form additional CO.

The gaseous mixture next passes upward through a reduction zone, where the steam and CO_2 continue to react with carbon; reaction finally ceases as a result of a progressive fall in gas temperature. The hot gas products next pass into the devolatilization and drying zones, where additional sensible heat is transferred to the coal. The principal constituents of the product gas exiting the gasifier are combustible CO and H_2, noncombustible CO_2, nitrogen diluent, and tars and water vapor. The gas also contains some light combustible hydrocarbon gases and smaller quantities of hydrogen sulfide (H_2S) and carbonyl sulfide (COS). In a commercial plant design, the tars and water vapor would normally be condensed out before the sulfur species are removed from the product gas.

Performance of Utah coal

UP&L's Blind Canyon seam coal is a moderate-swelling, low-sulfur B bituminous coal that is mined in large quantities in Emery County, Utah. A complete analysis of the coal is presented in Table 1. As can be seen, one of the coal's distinguishing features is that it has an extremely high volatile matter content. Approximately 350 tons of plus-¼-inch Utah coal was delivered to the Twin Cities site and stored without cover for four weeks before testing. As received, the coal contained many pockets of a brown-orange resin material. The coal was introduced into the gasifier on August 3, 1984, and the system ran continuously until the coal was depleted on August 11.

The coal gasified well during the test. Gas quality was good, with the higher heating value fluctuating between 170 and 180 Btu/scf (dry basis). Although limited by a leaking section in the gas duct to the combustion chamber, coal throughput was high, in the range of 1.6–1.9 t/h. The gasifier agitator was operated continuously to effectively manage coal agglomeration and to maintain high gas quality.

Table 2 presents design-point gasification data obtained from the test program at a nominal coal throughput of 1.80 t/h (109 lb/h/ft^2 of grate, or 532 kg/h/m^2) and a blast (air plus steam injection) saturation temperature of 145°F (63°C). As expected, the gasifier's thermal efficiency was high as compared with expected efficiencies when using either entrained-flow or fluidized-bed gasifiers.

On the basis of the analyses performed, the test data appear satisfactory. Measured total mass of material into and out of the gasifier during the Utah coal test balanced to within 4%; measured total heat into and out of the gasifier balanced to within 8%.

All material flows and compositions during the test were measured directly, except for the product gas volumetric flow rate. This rate was determined by dividing the mass rate of carbon in the gas (assumed to be equal to the measured mass rate of carbon in the feed coal minus the measured mass rate of unreacted carbon in the discharged ash) by the measured volume percentage of carbon in the gas. Unfortunately, this method of determining the gas flow rate precludes calculation of an elemental carbon balance; that is, the carbon species entering and leaving the gasifier are forced to balance exactly.

Table 3
TAR CHARACTERISTICS

Composition (wt%)	
Moisture (by distillation)	1.18
Sediment (solids)	0.59
Carbon	82.49
Hydrogen	8.97
Nitrogen	0.84
Sulfur	0.29
Oxygen (by difference)	5.64
Specific gravity at 60°F	1.0049
Flash point (°F)	247
Pour point (°F)	100
Kinematic viscosity at 122°F (cs)	109
Kinematic viscosity at 210°F (cs)	10.2

Tar characterization

EPRI contracted with Dr. George R. Hill of the University of Utah to characterize the high-quality tars that were produced in the Utah coal test (RP2505-3). Hill used a combination of thermogravimetry, liquid chromatography, low-voltage mass spectrometry, and computerized factor/discriminant analysis for the characterization.

Table 3 presents results from some of the tar analyses. It should be noted that at 210°F (99°C) the kinematic viscosities of tars from other bituminous and subbituminous coals gasified at the Twin Cities Research Center are in the range of 22 cs, compared with 10.2 cs for the Utah coal tar. Also, the hydrogen-to-carbon ratios for tars generated with other bituminous coals are in the range of 0.08–0.09 (weight fraction), compared with 0.11 for the Utah coal tar. The Utah coal tar consists of approximately 50 wt% hydrocarbons and 50 wt% heteroatomic compounds and is completely distillable under vacuum at 200°C. No major changes in the tar's bulk composition occurred over a 64-hour period at 80°C, although a marked darkening of the tar sample was observed.

Clearly, the tar produced from the Utah bituminous coal is of superior quality to tars produced from other U.S. coals in either moving-bed gasifiers or pyrolysis retorts. EPRI and UP&L are continuing to examine the Utah coal tar produced in the Wellman-Galusha gasifier and expect to fire the tar in a large-bore diesel engine at Transamerica Delaval, Inc., in the near future. *Project Manager: Michael Epstein*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

BOILER RELIABILITY

Statistical data collected on coal-fired units 400 MW and larger by the North American Electric Reliability Council (NERC) during 1974–1983 show that boilers and their related auxiliaries had an average equivalent availability of about 79%. During the last five of those years, the equivalent availability steadily improved, and in 1983 it was about 82%. This report describes EPRI's current and planned research to develop technologies and solutions for reducing availability loss due to boiler pressure part failures, maintenance, and coal quality effects.

Boiler tube failures

Boiler tube failures (BTFs) are the leading cause of availability loss in U.S. power plants. According to NERC statistics, the equivalent availability loss attributable to boiler tubes is over 6%. Despite a significant industry effort to prevent BTFs, more than 40,000 failures have been recorded in the last decade. A large percentage of these are repeat tube failures caused by the same mechanism. Failures have occurred in all boiler areas: economizers, waterwalls, superheaters, and reheaters. More than 80% of all BTFs force a shutdown, and a typical outage lasting three days can cost a utility $750,000 for replacement power.

As part of a multifaceted approach to the problem, EPRI has developed a boiler tube failure manual for power plant personnel (CS-3945). It is intended for use during investigations into BTF causes. EPRI believes that determining the correct failure mechanism and root cause in each case is of paramount importance in preventing future tube failures. Proper corrective action can then be taken to alleviate the root cause, adopt monitoring procedures, and eliminate repeat failures.

The manual categorizes 22 currently known boiler tube failure mechanisms. Color photographs show examples of each mechanism, and typical failure locations are illustrated. The manual also discusses probable root causes and how to verify them. Most important, it describes in detail the required corrective actions for preventing repeat failures.

In a follow-on activity, the manual's use will be demonstrated at a number of utility systems. By applying the methods presented in the manual and by introducing a root cause statistical data base into its system, a utility can better understand availability losses and can ultimately achieve a marked reduction in BTFs.

Of the 22 failure mechanisms described in the manual, only three appear to require further R&D in order to determine the root cause and then provide permanent solutions. EPRI has several projects that address these three areas.

- Corrosion fatigue tube failure in waterwalls and economizers
- Circumferential waterwall cracking in supercritical units
- Fire-side erosion and corrosion failure

Although the NERC data base does not detail root causes, discussions with utilities and boiler manufacturers suggest that the largest single loss of plant availability can be attributed to corrosion fatigue failures in waterwalls and economizers. In Canada, where a BTF root cause statistical data base has existed since 1980, corrosion fatigue failures account for more than 30% of all BTFs. The number of failures has been found to increase with the number of unit starts. This phenomenon will have important ramifications for the many U.S. utilities that are switching some units from essentially baseload operation to cycling or two-shift operation.

Corrosion fatigue cracks begin on the water side of waterwall and economizer tubing. Failures have predominantly been located where thermal expansion is restricted during transient conditions (such as startup during two-shift operation). Typical locations are at pressure-nonpressure attachments—such as tie bar, scallop bar, boiler seal, or windbox attachments and along the weld line in membrane waterwall panels. Figure 1 illustrates a windbox attachment.

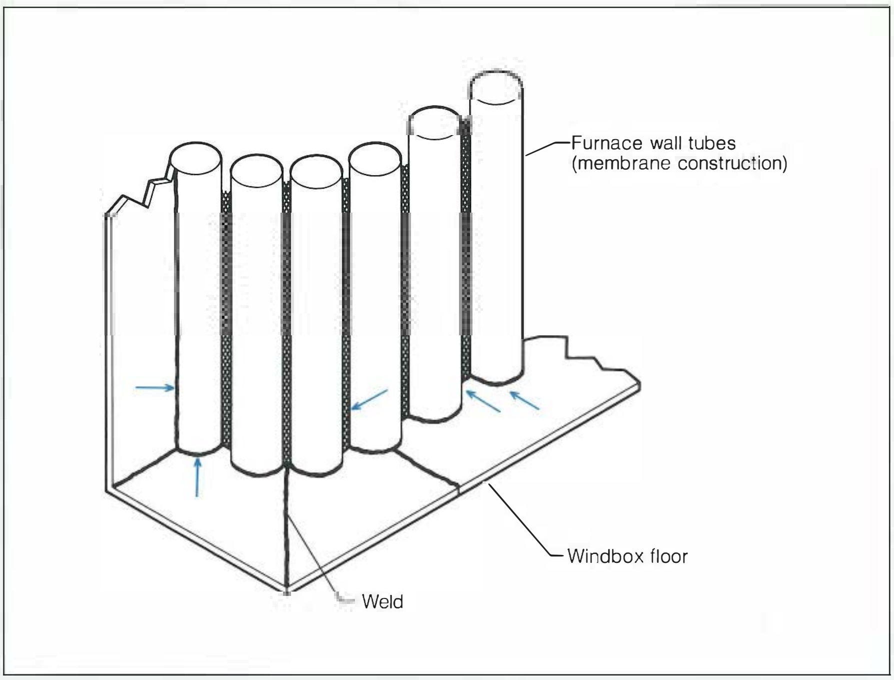
A project scheduled to start in August 1985 will address this failure mechanism (RP1890-5); its objectives are to determine the root cause and provide predictive techniques and solutions. Specifically, it will delineate the conditions of stress and boiler water environment (e.g., dissolved oxygen and pH) that are necessary for avoiding failure.

For the second failure mechanism under investigation, circumferential waterwall cracking in supercritical units, the region of concern is waterwall tubing in the highest heat flux areas—that is, just above the burner zone. The problem appears to be generic, since boilers of all the major manufacturers have experienced failure. Failures generally occur after about 7–10 years of service, and the root cause of the problem is not yet known. Experts think that thermal fatigue may be a contributing factor.

EPRI initiated a two-phase project to determine the root cause and provide operating solutions (RP1890-4). In the first phase, which is almost complete, investigators surveyed 20 supercritical units. They found that 10 of these units have severe or moderate cracking together with severe fire-side corrosion wastage. Five other units have severe corrosion with no identifiable cracking. Each utility has contributed operating, maintenance, and design data in an attempt to determine if the failures have a common generic factor. The second phase of the project, to be initiated early in 1986, will monitor pairs of supercritical units, one with cracking and one with no damage, to identify the root cause of the failures.

The third failure mechanism under investigation is fire-side erosion and corrosion. Again, because no statistical BTF data base exists, the exact ramifications of failures and maintenance activities associated with fire-side erosion and corrosion in U.S. fossil fuel

Figure 1 The junction of wall tubes and the windbox at a furnace corner is an example of the kind of pressure-nonpressure junction where boiler tubing corrosion fatigue failures generally occur. The arrows indicate typical crack initiation sites.



plants are not known. However, the industry considers this problem to be the second largest area of plant equivalent availability loss. These failures and the resulting damage occur in all regions of the boiler. Waterwalls, superheaters, and reheaters are known to suffer both erosion and corrosion, whereas economizer tubing usually suffers only erosion.

A variety of methods for preventing both fire-side erosion and corrosion are currently being applied. These essentially fall into two categories: palliative and permanent. Palliative measures include simple tube repair and replacement, tube thickness monitoring, pad welding of tubing, spray coating of affected areas, and shielding and baffling. The more permanent solutions rely on more engineering judgment. In the case of corrosion, several approaches have been tried, with varying success. These include fuel blending, coextruded tubing, and additives. In the case of erosion, hot gas velocities have been monitored. Because of current equipment limitations, however, this procedure can be performed only adjacent to the outside boiler walls. A more effective approach appears to be the monitoring of cold air velocities at partial gas flow, a technique used successfully in Australia, Canada, and Europe. This method enables better location of preventive diffusing screens, baffles, and shields.

EPRI has initiated a project to survey the state of the art in this area—specifically to identify the most effective methods being used to monitor the effects of fire-side erosion and corrosion and to counteract failures (RP2711-1). The project will assess the limitations of the current preventive and control technologies and provide direction for improving them and developing new technologies.

Remaining-life techniques

EPRI considers it important not only to determine the root causes of failures in major boiler unavailability areas (e.g., tubing and headers), but also to assess the remaining useful life of components under defined operating conditions. The overall objective of EPRI efforts in life assessment is to develop and validate nondestructive methods that represent significant improvements over current methods for estimating the remaining life of boiler pressure parts operating at elevated temperatures.

Steam pipes and heavy-wall, high-temperature header systems in boilers leak relatively infrequently. EPRI has recently completed a limited survey and examination of headers at 15 utilities, which revealed few major failures recorded to date. Still, many of the headers were found to have incipient damage that could result in failure if proper detection and corrective measures are not taken.

One method used to assess header damage is the replica technique. In this totally nondestructive procedure, a component's surface microstructure is reproduced by applying a cellulose acetate tape onto its surface. The investigators then examine the replica in a laboratory at high magnification to detect early stages of creep damage and to recommend a specific course of action. Although the general principle of replication has been known for some time, a recent EPRI project is responsible for demonstrating its potential to utilities in this country and for promoting its widespread successful application here (RP2253-1). Additional laboratory and field studies in this project are developing metallographic and miniature test specimen techniques that will complement the replica technique and provide a more quantitative basis for the life assessment of heavy-section components.

A new project will integrate the results of ongoing and planned EPRI studies into a generic, computer-oriented method for assessing the remaining useful life of thick-section boiler parts (RP2253-10). By identifying incipient problems before they lead to failures, this method will be a very important tool for improving boiler reliability.

The failure of superheater and reheater tubing is a frequent cause of boiler forced outage. A technique that monitors steam-side oxide scale growth is currently being developed to accurately determine the remaining useful life of such tubing (RP2253-5). Techniques that involve monitoring for tube wall thinning and accelerated creep testing have been successfully used in Canada and Europe. RP2253-10 will evaluate and compare all these techniques in order to provide utilities with the most cost-effective way of assessing tube life.

Coal quality effects

Two major coal-related impacts on boiler reliability are slagging and fouling. NERC data show that slagging and fouling cause an average plant availability loss of 1.6% annually. EPRI is assessing the effectiveness of coal cleaning and fuel additives in mitigating slagging and fouling problems in utility boilers. In RP2425-1 run-of-mine coals cleaned at EPRI's Coal Cleaning Test Facility are being combustion-tested at pilot scale to quantify the beneficial effects of coal cleaning on slagging, fouling, and fire-side erosion. In pilot- and full-scale tests in RP1839-4, researchers are evaluating the use of minute quantities (2–5 ppm, coal basis) of such volatile additives as copper oxychloride to reduce slagging. Fundamental research on the effects of key components of coal mineral matter (e.g., iron pyrites) is being conducted in RP2425-3. And finally, on the basis of data obtained from an extensive utility survey, RP1891-1 researchers are developing correlations between boiler slagging and fouling, coal characteristics, and boiler design and operating conditions.

The major coal-related impacts on pulverizer reliability are (1) fires and explosions and (2) abrasion and erosion. In RP1883-1 EPRI is sponsoring an investigation of improved methods for detecting, controlling, and preventing spontaneous fires and explosions in coal pulverizers. In RP1883-2 researchers are identifying relationships between coal characteristics and abrasive wear rates in coal pulverizers and are establishing an improved basis for specifying wear-resistant materials; the results to date indicate that coarse (> 45 μm) quartz grains in the coal are the major cause of abrasion. Researchers in RP1883-5 are studying materials and methods for reducing erosion in pneumatic pulverized-coal conveying systems.

Although the effects of coal quality on plant reliability and availability are generally known to be significant in terms of cost, there are no accurate correlations for quantifying these cost impacts. EPRI has sponsored a state-of-the-art review in this area (RP2256-1) and is now planning a second phase to develop a computer-oriented method for assessing how variations in coal quality affect equipment performance, availability, and maintainability (RP2256-2). This work will integrate results from all the EPRI coal quality projects on slagging, fouling, combustion, corrosion, and erosion.

Boiler maintenance

From 1972 to 1981 the average scheduled outage factor for all sizes of fossil fuel utility boilers was 8%. EPRI believes that the application of new, creative boiler maintenance and repair technologies could reduce outage hours by up to 20%, with a concomitant 2% improvement in the availability of larger units.

EPRI's work in this area began in 1984. The first project is assessing the state of the art in boiler and related auxiliary equipment maintenance and repair technology (RP2504-1). Project personnel will detail the top 15–20 boiler maintenance activities (in terms of man-hours and costs) conducted by U.S. utilities. The second phase, to be initiated early in 1986, will develop advanced technology—including planning systems, work methods, inspection procedures, and tools—for reducing the frequency and duration of major outages.

In summary, EPRI recognizes the serious financial impact boiler availability losses have on utility resources, and believes that this impact can best be reduced through a combination of several factors: a proper understanding of root causes, the development of solutions to counteract root causes, the development of root cause data bases (particularly for BTF), the application of preventive and advanced maintenance techniques, and the thorough use of remaining-life techniques. EPRI is working to provide the technologies and tools so that utilities can accomplish this end. *Project Manager: R. B. Dooley*

INTEGRATED ENVIRONMENTAL CONTROL

Recent results from the integrated environmental control pilot plant (IECPP) at EPRI's Arapahoe Test Facility demonstrate potential cost savings for environmental controls from considering the entire system rather than individual controls for wastewater, solids management, and flue gas emissions. This phase of testing, which used a fabric filter–wet SO_2 scrubber configuration, identified methods of reducing wastewater discharge to meet zero discharge requirements or revised National Pollutant Discharge Effluent Standards. Specifically, the results provide guidelines for (1) employing flue gas desulfurization (FGD) systems for wastewater disposal without compromising SO_2 removal or solid-waste properties, (2) reducing solid-waste dewatering requirements without incurring solids handling or disposal difficulties, and (3) improving water management to aid mist eliminator cleaning for zero water discharge. In addition, the tests evaluated the effect of waste heat recovery systems on plant water management and solids handling. Design studies indicate that the application of such integration concepts can offer savings of 2–5 mills/kWh, depending on fuel composition, site conditions, and environmental regulations.

The objective of the divisionwide integrated environmental control program is to develop an environmental control strategy that considers all aspects of power production—from fuel and site selection to waste generation—in identifying the least-cost control approach. The IEC program consists of pilot plant tests and design studies; the results are directed both to new units and to retrofits.

Pilot plant tests

The IECPP provides valuable experience with relatively untried environmental controls that offer potential for cost savings but that, compared with conventional approaches, increase risk for first-time users. Located at the Arapahoe Test Facility in Denver, Colorado, the IECPP processes a flue gas slipstream of 5000 scfm (2.4 m^3/s)—nominally equivalent to 2.5 MW (e). In 1985 the plant will have capabilities for particulate control by electrostatic precipitation (ESP) or fabric filtration and SO_2 control by wet scrubbing, spray drying, or dry sorbent injection.

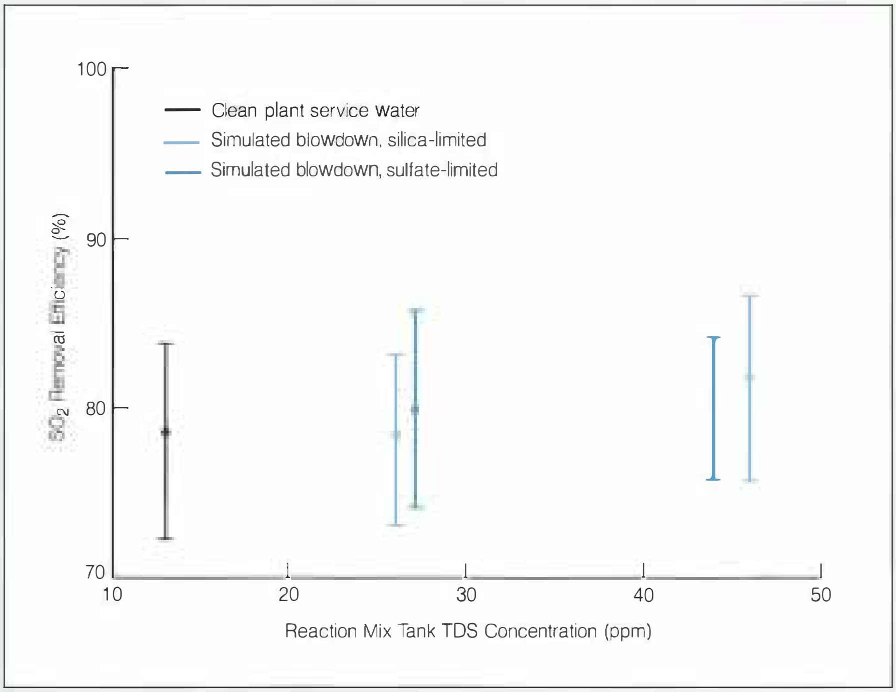
From December 1982 through August 1983, Brown & Caldwell conducted tests at the plant to evaluate a control configuration consisting of a wet limestone scrubber preceded by a fabric filter (RP1646-4). Since there is little full-scale experience with this configuration—particularly under closed-loop water management, which may be required in the West—detailed measurements were made to characterize environmental control performance and heat rate effects. These covered flue gas emissions, wastewater discharge, the physical characteristics of solid waste that influence handling and containment, and factors affecting heat rate (e.g., auxiliary power and acid dew point). The work explored integrated design concepts for managing wastewater under closed-loop conditions while providing acceptable solid-waste characteristics and minimizing plant heat rate.

The largest source of wastewater in plants with wet cooling towers is cooling-tower blowdown (nominally 1 gal/min, or 3.785 L/min, per MW), which results from the purging required to control recirculating-water solids content and scaling. Blowdown is currently used to a limited extent to supply makeup water for limestone scrubbers. However, application limits for blowdown with a high total-dissolved-solids (TDS) content in terms of risks to SO_2 control and waste management have not been defined. If high-TDS blowdown (~5000 ppm) can be used in scrubbers at plant sites with restricted water discharge, wastewater disposal facilities can be reduced or eliminated, saving 1–2 mills/kWh (depending on fuel properties and site characteristics).

To evaluate the use of cooling-tower blowdown in a limestone scrubber, four blowdown compositions were simulated for the IECPP tests; these waters were characterized by an inlet TDS concentration of either 3000 or 5000 ppm and limited by either silica or sulfate saturation. Figure 2 compares SO_2 removal for the four types of simulated blowdown and for clean service water at an inlet SO_2 concentration of 2000 ppm. The results indicate that the use of simulated blowdown had no significant effect within the uncertainty of analytic measurements and the precision of pilot plant control.

However, differences in the unconfined compressive strength (UCS) and permeability of the waste materials (fixated mixtures of fly ash and scrubber waste) were observed in the tests. These suggest that the use of cooling-tower blowdown may limit the range of ash-sludge-lime mixtures that can provide accept-

Figure 2 Pilot plant tests were conducted at fixed operating conditions to evaluate the use of high-TDS wastewater (as generated by cooling towers) for scrubber makeup. Clean plant service water and simulated wastewaters whose inlet TDS content approximated that of tower blowdown (3000 to 5000 ppm) were tested. The results show that the use of high-TDS wastewaters, whether silica- or sulfate-limited, did not adversely affect scrubber performance.



able compressive strength (i.e., greater than 200 psi, or 1.38 MPa). Without corrective measures, this limitation could mean increased difficulty in solids handling and land reclamation. The change in solid-waste properties will be analyzed in future pilot plant tests with the ESP–wet scrubber configuration, which is expected to produce similar waste, and corrective measures will be identified.

One test revealed an anomaly in waste particle formation and dewatering that could lead to the simplification of waste management system design. Results at a low SO_2 concentration (300–400 ppm) showed no change in SO_2 removal for the 3000-ppm-TDS, silica-limited water as compared with service water, but showed significant increases in sulfite oxidation (85% versus 45%), particle settling velocity (0.04 versus 0.008 ft/min [0.2 versus 0.04 mm/s]), and thickener underflow solids content. Under these conditions crystal growth processes within the thickener changed radically, producing very hard, rocklike particles up to 1 inch (2.54 cm) in diameter. Particle analysis found up to 60% of the composition to be a complex magnesium carbonate compound, which suggests particle growth by coprecipitation of magnesium and carbonate compounds from blowdown in the thickener.

Although this particle growth mechanism could complicate the handling and dewatering of solids from conventional-design thickeners (as witnessed in the IECPP test), it could be exploited through new equipment design to minimize solids handling and waste management. For example, at existing plants with scrubbers that employ settling ponds, the use of cooling-tower blowdown to minimize wastewater disposal could have the added advantage of enhancing solids settling in the disposal ponds. At existing or new plants with conventional primary and secondary dewatering, the high thickener underflow resulting from this effect could permit secondary dewatering processes (which usually require significant maintenance and auxiliary power) to be bypassed. Tests with the ESP–wet scrubber configuration will further study this effect and determine to what extent these results can be generalized to different makeup waters, fuels, and SO_2 levels.

Other water management tests conducted at the pilot plant concerned (1) the potential for increasing the disposal of wastewater with waste solids when landfill design does not require extremely low permeability (i.e., $<10^{-6}$), and (2) the frequently incompatible goals of minimizing flue gas pressure drop in the mist eliminator and maintaining plant water balance.

Data suggest that for low-sulfur fuels, a higher moisture content in the solid waste may be desirable at some plant sites as a way of providing for additional wastewater disposal while still meeting requirements for solid-waste physical properties. Although conventional wet FGD design calls for maximum dewatering of FGD wastes, this may not represent the least-overall-cost approach for wastewater and solids disposal at all sites. Figure 3 illustrates a hypothetical relationship between UCS and water content for combined FGD and ash wastes as suggested by selected IECPP results. These results indicate that for a UCS of 200 psi (1.38 MPa), which usually provides adequate solids handling and disposal properties, a water/solids ratio approaching 0.7 can be tolerated; this would enable the disposal of an additional 50–75 gal/min (3.2–4.7 L/s) of wastewater and offer nominal savings of $800,000 a year in operating costs for a 500-MW unit.

In the mist eliminator cleaning tests, a horizontal-gas-flow unit was used, and wash water was separated from scrubber recycle water. Several wash water sources and recycling schemes were evaluated in terms of their ability to maintain low pressure drop and minimize plant water makeup requirements. The tests were not intended to analyze mist eliminator particulate removal capabilities, but to assess the advantages of mist eliminator water management independent of the scrubber. (In-depth testing and analysis of horizontal and vertical mist eliminator performance at full-scale plants are being conducted under RP2535.)

The most significant result was that the amount of fresh water available for mist eliminator cleaning was increased by applying low-water-loss mechanical seals to scrubber slurry pumps. By reducing freshwater leakage through slurry pump seals (40% of the pilot plant makeup), additional water could be directed to the mist eliminator. This modification permitted the mist eliminator pressure drop to be maintained at less than 0.5 inch H_2O (0.12 MPa) while maintaining closed-loop water management.

For a typical 500-MW plant, freshwater leakage through slurry pump seals can represent 20–50% of scrubber makeup. Because experience with low-water-loss seals at full-scale plants is limited and their reliability and maintenance requirements are largely unknown, several utilities are evaluating different seal designs for plant application. Savings of at least $100,000 a year in operating costs are available from each pressure drop reduction of 1 inch H_2O (0.25 MPa) that is achieved.

For plants where applying low-water-loss seals is not practical, mist eliminator cleaning tests using recycled water from various in-plant sources were conducted. Results obtained over approximately six months showed that pressure drop intentionally allowed to increase to more than 6 inches H_2O (1.5 MPa) could be rapidly reduced to less than 0.5 inch for most water recycling schemes. The best performance in terms of maintaining a low pressure differential (i.e., 0.5–1 inch H_2O) with minimum water consumption was obtained by washing with thickener overflow for 10 minutes every 8-hour shift; this practice completely eliminated the need to add fresh water at the mist eliminator.

Tests to define low-heat-rate designs evaluated the influence of waste heat recovery on scrubber SO_2 removal, water management, and solid-waste properties. The potential payoff for successfully integrating waste heat recovery and eliminating the need for flue gas reheating is up to 3 mills/kWh, depending on fuel sulfur content. Tests were conducted at low (~300 ppm) and moderate (~2000 ppm) SO_2 concentrations to determine the effects of the lower scrubber inlet temperatures produced by waste heat recovery—as much as a 100°F (56°C) reduction from a nominal temperature of 250°F (121°C). Preliminary observations that there is negligible effect on SO_2 removal, calcium utilization, and solid-waste properties (*EPRI Journal*, September 1983, p. 40) have been confirmed for both low- and medium-sulfur conditions. These results suggest that utilities can reap the benefits of waste heat recovery without incurring significant cost penalties for SO_2 removal or water management.

However, the resulting decrease in water evaporation rate—175 gal/min (11 L/s) for a 60°F (33°C) reduction for a 500-MW plant, or approximately 35% of total evaporative capacity—could increase water management costs, especially if FGD processes are used for wastewater disposal or if mist eliminator washing requires significant quantities of fresh water. Additional costs for disposing of this wastewater will offset gains from waste heat recovery; thus, economic analysis should fully consider water management costs.

Through the mass and ion balances conducted for all gaseous, liquid, and solid input and output streams, the IECPP tests identified a previously undetected nitrogen-sulfur compound in scrubber water and solids. The compound accumulated to as much as 30% (equivalent as sulfate) of total sulfur compounds in the dissolved slurry fraction. Ion chromatography identified the general form of the compound to be a derivative of hydroxylamines; it is not clear if any one specific compound dominates.

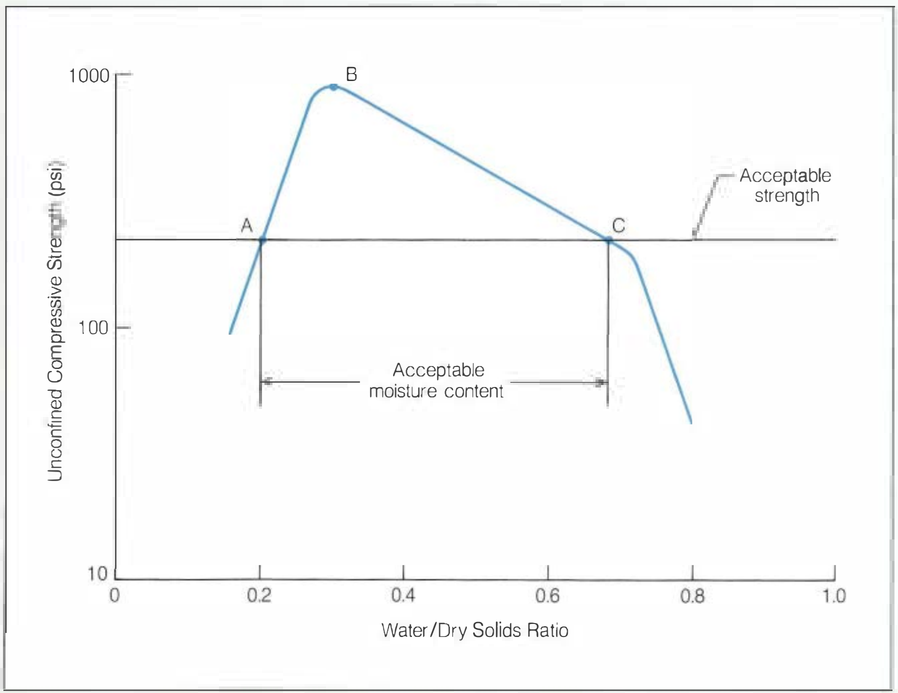


Figure 3 IECPP test results on mixtures of FGD wastes and fly ash suggest that acceptable UCS values can be obtained for a wide range of waste moisture content—and thus that solid-waste disposal can be used to help reduce wastewater disposal costs. This curve is based on selected IECPP results and on the general behavior of solid-liquid mixtures undergoing cementitious reactions. Point *A* indicates the optimal moisture content when transportation dominates waste disposal costs (i.e., when it is desirable to minimize waste mass); *B* is optimal when maximum UCS and low permeability are necessary to meet landfill requirements; *C* is optimal in arid regions, where wastewater disposal costs are high and solids disposal can assist in water evaporation.

Because the concentration of the nitrogen-sulfur species could not be independently controlled, it is not possible to determine from these test results the compound's role in limestone scrubber chemistry, its influence (if any) on scrubber performance, or the mechanisms of its formation. However, comparing its concentration history with scrubber operating conditions and changes in flue gas and water composition across the scrubber permits the following speculations.

- The source of nitrogen is NO and NO_2 removed by the scrubber, in quantities that depend on the SO_2 concentration. NO removal was 30–50 ppm at 300 ppm SO_2 and 20–40 ppm at 2000 ppm SO_2.

- Tight water management (i.e., restricted water discharge) is necessary for the accumulation of the nitrogen-sulfur compound to detectable levels in the dissolved slurry fraction. IECPP scrubber cycles of concentration were 30–35 and 6–8 for low- and high-SO_2 concentrations, respectively, which are greater than those (3 or 4) for most full-scale units in commercial operation.

- Low oxidation in the scrubber slurry (i.e., a high sulfite content) contributes to the formation of the nitrogen-sulfur compound. Despite a high flue gas oxygen content (9–10%), low oxidation was evident in the IECPP slurry (~1/1 sulfite/sulfate)—possibly because of the high fabric filter collection efficiency and subsequent low concentrations of ash-generated oxidation catalysts (iron and manganese).

Additional work to define the significance of nitrogen-sulfur compound formation has been conducted for EPRI's Desulfurization Processes Program by Radian Corp. (RP1031). It included tests with bench-scale facilities and the IECPP scrubber. The objective was to determine whether nitrogen-sulfur compounds influence the design and operation of wet scrubbers—that is, whether design criteria for scrubbers operating downstream of fabric filters and under tight water management differ from those for other applications. The results were reported at the 9th EPRI–EPA Symposium on Flue Gas Desulfurization in June 1985; an EPRI report is forthcoming.

Design studies

Studies by Stearns-Catalytic Corp. (RP1609-1) have produced a strategy to help plant designers identify the optimal environmental control system (ECS) configuration for given site, fuel, and regulatory constraints. The results of the project can also be used to infer the influence of fuel composition on ECS costs; they suggest that these costs generally correspond to, but are not solely dictated by, fuel sulfur content.

The project team proposed a preliminary design strategy and applied it to 13 hypothetical power plants representing typical U.S. site and fuel conditions. The site-fuel combinations defining the hypothetical plants are as follows.

- Northeast (New Jersey): medium-sulfur and high-sulfur Appalachian coals
- Southeast (Florida): medium-sulfur Appalachian coal, Illinois coal (uncleaned in one case and cleaned in another)
- Gulf Coast (Texas): Yeagua Jackson lignite, Wilcox lignite
- Midwest (Illinois): Illinois coal, Powder River Basin coal
- Rocky Mountain (Utah): Powder River Basin coal, Wasatch Plateau coal (with high-quality plant makeup water in one case and low-quality makeup in another)
- Far West (southern California): Wasatch Plateau coal (with stringent environmental controls)

The design strategy was used to reduce the number of ECS candidates at each plant to a few for final design. The systems were defined according to their means of SO_2 control (wet throwaway, alkaline ash, spray drying, dual alkali, dry sodium injection, sulfur recovery); particulate removal (ESP, fabric filtration); heat rejection (once-through, wet, wet-dry, or dry cooling); and solid-waste management (ponding, fixation of scrubber waste and ash, scrubber waste oxidation and stacking, ash and scrubber waste by-product marketing). Wastewater management schemes and flue gas reheating systems were tailored specifically for each ECS. Where feasible, coal cleaning was considered for sulfur and ash removal. Design for stringent emission limitations (southern California) required 95% SO_2 removal and selective catalytic reduction for NO_x control.

As a result of variations in fuel cost, site conditions, and environmental control requirements, electricity costs varied significantly among the approximately 125 ECS designs examined for the 13 power plants. The Gulf Coast plant firing the Wilcox lignite had the lowest electricity costs, 71–77 mills/kWh, because of relatively low fuel costs; the Wasatch Plateau–fired southern California plant had the highest, 111–117 mills/kWh, because of strict environmental control.

The results suggest that the cost of environmental controls corresponds to fuel sulfur content, but that other fuel properties (e.g., heating value, ash content, ash composition), site characteristics (e.g., water availability, solid and liquid waste disposal options), and environmental regulations can mitigate the influence of sulfur. For example, although fuel sulfur content varied from 0.48% to 4.0% for 12 plant designs, the least-cost control systems were all approximately 13–16 mills/kWh. (Two exceptions were for a low-heating-value Gulf Coast lignite and a high-sulfur [4.0%] Illinois coal.) The cumulative effect of site characteristics and fuel properties other than sulfur content can be equivalent to a change of 1–2% in coal sulfur content. Accordingly, the fuel with the lowest sulfur content may not always provide the lowest-cost ECS.

Two IEC reports for use by utilities in planning new capacity or retrofits are forthcoming. The design strategy developed to help utility planners select the best environmental control configurations for new plants on the basis of site, fuel, and regulatory conditions will be available in August 1985. A detailed description of the IECPP fabric filter–wet scrubber test results, complete with a guide for application, will be available in October 1985. Future IECPP tests are planned for these configurations: ESP–wet scrubber, spray dryer–ESP, and spray dryer–fabric filter. Results are expected to be available in 1985 and 1986. *Project Manager: J. Edward Cichanowicz*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

POWER SYSTEM PLANNING AND OPERATIONS

Near-term enhancements to EGEAS

The first phase of RP1529 developed a computer program, EGEAS (electric generation expansion analysis system), to help utility planners carry out the three primary analysis functions in generation planning: optimal generation expansion, reliability analysis, and production cost calculations. EPRI initiated phase 2 of the project with Stone & Webster Engineering Corp. in September 1983 to enhance EGEAS in several ways (*EPRI Journal*, October 1984, p. 49). The contractor has completed the following enhancements.

- A model for the economic utilization of stor age units
- A model for must-run units and spinning reserve requirements
- Modifications to the dynamic programming optimization option, including a restart feature and a file-merging capability
- Expansion of the report generator program's capabilities to provide information on loading order, maintenance schedules, storage units, and neighboring-system characteristics

A revised version of EGEAS incorporating these features was distributed to more than 65 member utilities through the Electric Power Software Center in early February 1985.

The remaining enhancements—the inclusion of incremental cost information in the production cost models, the development of an energy purchase/sales model, and the representation of storage units in the Bender's decomposition optimization option—are scheduled for completion by October 1985. *Project Manager: Neal J. Balu*

Power plant performance

Increasing fuel, labor, and equipment costs make it mandatory to demonstrate new techniques for improving the performance and dispatch of existing fossil fuel power plants. In response to this situation, EPRI's Coal Combustion Systems Division and Electrical Systems Division undertook a large joint project (RP1681, RP2153) as a single demonstration for the industry.

Potomac Electric Power Co. (Pepco) was selected as the host utility and prime contractor. The primary subcontractors include Power Technologies, Inc.; Lehigh University; Combustion Engineering, Inc.; and General Electric Co. Power Technologies is performing work related to turbine analysis, software development, instrumentation selection, data acquisition system development, and system dispatch studies. Lehigh is involved in boiler performance optimization. Combustion Engineering is assisting in boiler modeling and heat transfer analysis. General Electric is conducting a critical review of the turbine cycle test instrumentation, as well as providing information on turbine design and operation.

The host generating unit, Morgantown Unit 2, is a coal-fired, supercritical once-through unit with an electrical output of 575 MW. Combustion Engineering supplied the boiler, and General Electric the turbine generator unit. The Morgantown plant and Pepco's system control center are serving as test facilities to determine the value of instrumentation enhancements, increased computer use, plant modeling improvements, modifications in plant control and operating procedures, improved data transfer between the power plant and the energy control center, new or improved plant models for use in system planning and operation, and enhancements to system economic dispatch and unit commitment.

A team of 27 experts from other utilities are acting as industry advisers to the project. A three-day workshop was held in Washington, D.C., in October 1984 to report the results of the early work to the industry; approximately 230 people attended.

One initial project effort, an incremental heat rate sensitivity analysis, included the development of a simulator for analyzing how changes in a plant's operating state affect the plant fuel consumption and the system dispatch for four types of cycling and baseload coal-fired units. Studies using the simulator provided the following results. Deviations in exhaust pressure from design values produced one of the most significant effects on fuel consumption of all the changes in plant operating conditions. For one Pepco unit, a deviation of +0.75 inch Hg (2.5 Pa) resulted in an increase of 0.3% in system daily fuel cost.

Other research in this area involved the impact of modeling and measurement errors. The requirements for convex input/output curves introduced a modeling error of 0.25–0.3% rms and 0.8–1.0% maximum for the Pepco units studied. Both bias and random measurement errors above 2% of rated input significantly affected the incremental heat rate analyses. It was found that for these units, errors in measurement or modeling as small as 1% could conceal the effects of changes in steam conditions and condenser back pressure.

The boiler performance optimization research included a parametric analysis, instrumentation assessment, and boiler test preparation. The parametric analysis indicated that the net heat rate increases substantially as the level of excess air is decreased from 30% to 10%. With finer coals (70–75% through 200 mesh), the relationship between heat rate and the percentage of excess air is relatively flat over the range of 15–30% excess air, with the heat rate increasing at lower levels of excess air because of relatively high carbon loss. As the coal fineness is increased to 85% and excess air reaches a minimum of 13.5%, the overall excess air level and the reduced exit gas temperature provide a 100-Btu/kWh reduction in heat rate.

The instrumentation assessment effort focused on the following: methods to eliminate fuel-air imbalances between burners; instrumentation to monitor tube wastage rates; measurements of gas temperature, gas species, and wall heat flux in the furnace region; instrumentation near the regenerative air preheater; and methods to determine the instantaneous unit heat rate. *Project Managers: John W. Lamont (Electrical Systems) and Frank Wong (Coal Combustion Systems)*

UNDERGROUND TRANSMISSION

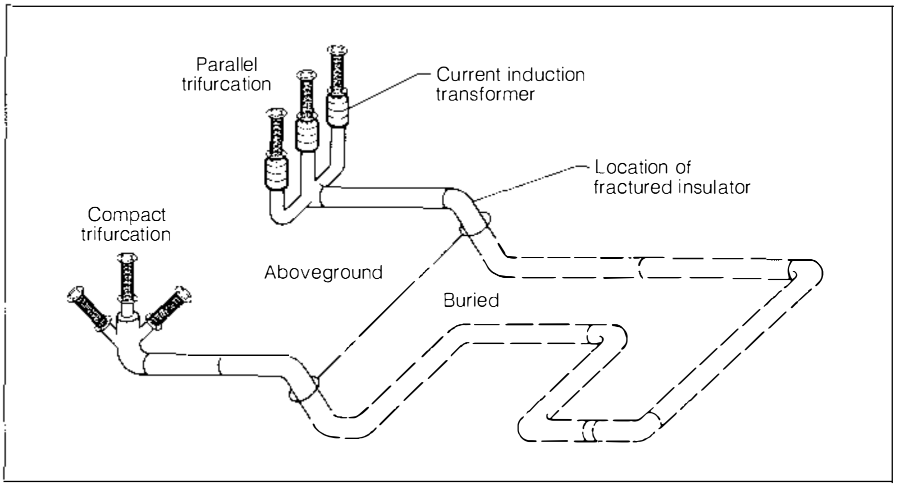
Field demonstration of three-conductor gas cable

In a cost-shared effort, Detroit Edison Co. contracted with EPRI to demonstrate a new 345-kV, three-conductor, gas-insulated transmission cable (RP7840-2). Westinghouse Electric Corp., the cable manufacturer, supplied a 183-m (600-ft) loop to Detroit Edison for installation, testing, and operation as an integral part of the utility's transmission system. Because the 71-cm-diam (28-in) cable enclosures designed by Westinghouse were too large to be extruded in one piece, they were made of three 120° extruded aluminum segments that were welded together longitudinally. An automatic welding line for the enclosure segments was developed to ensure uniform weld quality and to lower the hardware cost.

The test loop, which was installed at Detroit Edison's Wayne station, included two termination designs and a wide variety of cable sections and bends; both aboveground and belowground thermal environments were represented (Figure 1). An extensive monitoring and data acquisition system was installed, and the cable system was to undergo approximately two years of operation and testing featuring a variety of high current ratings. The schedule called for the following sequence of tests (with the system energized at 345 kV): a normal system current test (nine months); three successive cyclic-induced-current tests, (three months each), at 1000 A, 1500 A, and 2000 A, respectively; and a 2000-A continuous-induced-current test (three months).

After 19 months of testing, the system sustained an interruption during the 2000-A continuous-induced-current test. Investigation disclosed that the problem was in a factory-assembled, 45° section, just above ground level on the parallel trifurcation end (Figure 1). When the system was degassed and opened, the investigators found that an insulator was fractured at the epoxy–metal insert interface near the enclosure (Figure 2). Removal and subsequent laboratory analysis by Westinghouse verified that the mechanical fracture occurred first, triggering an electrical flashover. The question was, why did the insulator fracture? A quick inspection of the parallel trifurcation provided the answer.

Figure 1 Layout of the Detroit Edison three-conductor, gas-insulated underground transmission cable test loop. The 345-kV, 2000-A loop, which is 183 m (600 ft) long, was manufactured by Westinghouse Electric Corp.



Thermal expansion of the aboveground portions of the test loop was accommodated by allowing the cable and termination (trifurcation) assemblies to slide on low-friction bearing pads. A normal termination assembly is relatively lightweight and will slide when expansive forces build. In the Wayne station test loop, however, the very heavy current induction transformers that are part of the parallel assembly hindered the sliding action necessary to relieve the expansive forces. A visual inspection of the parallel termination bearing pads showed that sliding had not occurred; as a result, the unaccommodated expansive forces fractured an insulator and triggered an electrical flashover. The interruption was explainable and preventable, an artifact of the test installation that would not occur in normal installations.

Because the testing was nearly complete and the repair would be costly, the demonstration was terminated. A final report is now being prepared. *Project Manager: John F. Shimshock*

Figure 2 Cable testing was interrupted just short of completion by the mechanical failure of this insulator, which triggered an electrical flashover. The very heavy current induction transformers, not normally part of an operating system, prevented the termination assembly from sliding during expansion.

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Temporary operation of motors with cut-out coils

Stator winding failures in power plant induction motors do not occur frequently, but they happen often enough to be of concern to utility operating personnel. When such a failure occurs, it frequently causes a forced outage of the generating unit or, at best, operation at less than rated load until the motor can be put back on-line. Most such motors can be reconnected fairly quickly, often with full capability, for operation until permanent repairs can be made without penalizing unit availability. Since utility personnel have generally not had access to information about reconnecting these motors, they have had to rely on manufacturers or outside service shops, with attendant delays and financial loss.

The objective of RP2330-1 is to produce a method utility personnel can use to temporarily reconnect and operate power plant induction motors that have experienced stator winding failures. The manual resulting from this project presents a simple, straightforward procedure that meets this objective. Utility personnel with a minimum of motor repair experience can use it to get a motor with a failed stator winding into temporary operation quickly and effectively.

For most induction motors in power plant service, the manual will enable utilities to accomplish the following specific tasks.

- Determine which coils need to be cut out of the stator winding circuit
- Reconnect the motor properly
- Estimate the currents and temperatures of an operating modified motor
- Prevent excessive motor noise and vibration

The manual also contains practical techniques for physically reconnecting the motor, together with precautions necessary for avoiding problems. It contains examples of the required calculations for most winding types found in modern power plant motors. Finally, for those wishing to pursue the process in greater detail, an appendix presents a complete description of the mathematical analysis. The manual has been published as an EPRI report (EL-4059). *Project Manager: J. C. White*

New alloy for retaining ring application

The July/August 1984 *EPRI Journal* (p. 50) described in detail the reasons for, and the initial progress of, an effort to develop a new high-strength retaining ring alloy (RP1876). Since then, scale-up studies have been completed on the optimized Nb-Ta alloy T composition.

A defect-free 5000-lb (2270-kg) billet of the alloy was successfully manufactured by Carpenter Technologies from an ingot that had undergone vacuum induction melting and then vacuum arc remelting. The billet was cut into three equal sections, each of which was forged into a doughnut-shaped ring at the Ladish Co. The rings were then hot-rolled; cold-expanded by 20%, 25%, and 30%, respectively; and heat-treated. All the rings met or exceeded the program goal of achieving a yield strength of 200 ksi (1380 MPa). Ultrasonic inspection of the rings, using standard General Electric Co. procedures, showed them to be defect free. The highest yield strength—215 ksi (1480 MPa)—was achieved in ring 3, which had been cold-expanded by 30%. Test specimens from this ring were therefore chosen for more-detailed evaluations.

Several tests have been completed on the ring 3 material. The results to date indicate that the properties of this high-strength material are comparable or superior to those reported for the currently used, lower-strength (180 ksi; 1240 MPa) 18Mn-5Cr and 18Mn-18Cr alloys, which were tested under the same conditions. Hot tensile tests to 500°C also showed the ring 3 material to be much more stable. At 150°C, for instance, the 18Mn-18Cr alloy exhibited a 17% drop (30 ksi; 210 MPa) in yield strength, the 18Mn-5Cr alloy a 5% drop (10 ksi; 70 MPa), and the ring 3 material only a 1% drop (3 ksi; 20 MPa).

In the range from −196° to −143°C, the Charpy energy varied from 22 to 43 ft-lb (30–58 J) in the ring 3 material, 10 to 40 ft-lb (14–54 J) in the 18Mn-5Cr alloy, and 9 to 180 ft-lb (12–244 J) in the 18Mn-18Cr alloy. The room-temperature Charpy energy was above acceptable levels in all three alloys. The ring 3 alloy showed no degradation in room-temperature tensile property after aging at 300°, 400°, and 500°C for up to 25 hours, whereas the 18Mn-5Cr alloy showed significant degradation after 25 hours of aging at 500°C. Also, the ring 3 alloy showed no significant effects of strain rates in the range of 10^{-2} to 10^{-6} in/s, whereas both the 18Mn-5Cr and 18Mn-18Cr alloys showed a significant drop in tensile ductility (~30%) and yield strength (up to 15%) with a decrease in the strain rate.

Results from short-term (100-hour) stress relaxation tests at room temperature, 50°C, and 200°C at two different strain levels (4 and 5.7 mils/in; 40 and 57 μm/cm) indicated no evidence of stress relaxation in the high-strength (215-ksi) ring 3 alloy; under identical test conditions, however, the lower-strength (~180-ksi) 18Mn-5Cr and 18Mn-18Cr alloys showed approximately 10% and 6% drops in stress. The strain level of 4 mils/in used in the test is typical of that calculated for the high-strength rings at 20% overspeed. Thus the General Electric–EPRI alloy appears to be superior to current alloys with regard to stress relaxation resistance.

Low-cycle fatigue (LCF) tests in air were also conducted as part of the detailed evaluation of the ring 3 material. The results indicate that the LCF resistance of this high-strength ring is comparable to that of the 18Mn-18Cr and 18Mn-5Cr rings.

In summary, a prototype 52-in-diam (132-cm) ring from the new alloy developed by EPRI has been successfully produced. The ring meets all the program objectives with respect to domestic manufacturability, high strength, and stress corrosion resistance. The market need for such a ring alloy has diminished drastically since the inception of this project, however, and this activity is deemed to be essentially complete. The final report on the project will be issued in August 1985. *Project Managers: R. Viswanathan and D. K. Sharma*

OVERHEAD TRANSMISSION

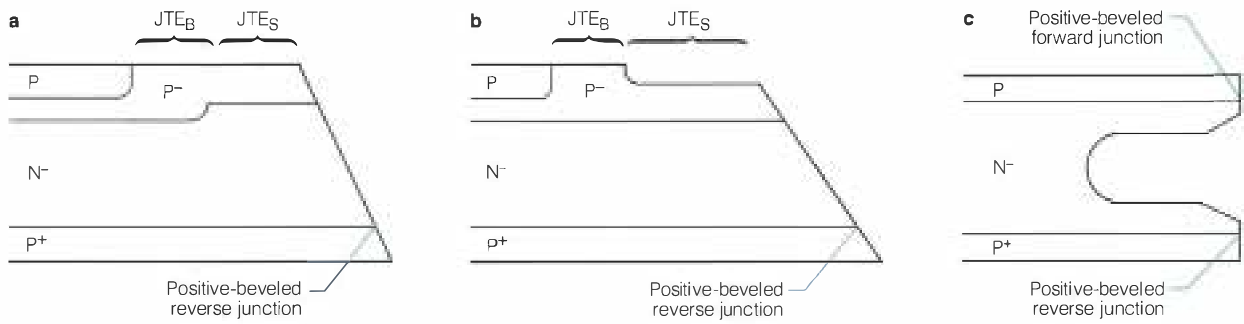
Transmission line induction effects

Sometimes when one touches a large metal object under a high-voltage power line, he or she notices a small shock. Because this is an effect of the line and can be an annoyance, transmission line designers calculate the magnitude of such shocks and design lines accordingly. Most of the time, the charge on an object under a line, say a car, is small and the shock is imperceptible. With a large vehicle like a truck, however, certain conditions will result in a noticeable shock—very much like the carpet shock everyone has experienced.

Until now, engineers have generally calculated induction effects as a series of worst-case conditions leading to a shock, even though they know such conditions can be much more severe than the real-world situation. Accuracy requires a probabilistic analysis. Thus the staff at EPRI's High-Voltage Transmission Research Facility, assisted by Enertech Consultants, Inc., is developing a method for assessing ac line induction effects on a probabilistic basis (RP1591-1). In all cases this method is more accurate than currently used calculations, and in most cases the calculated effect is less severe.

The first step in this project was to develop an assessment framework that would combine a situation analysis (situations per year) with an effects analysis (effects per situation) to yield a frequency of occurrence (effects per year). For example, how many times a year will a farmer drive his tractor under the transmission line, and for each time he does, what will be the induction effect (below perception, percep-

Figure 3 New thyristor edge geometry for high breakdown voltage and low surface fields. Three approaches were explored. The first (**a**) features two ion-implanted and -diffused junction termination extension (JTE) zones, zone JTE_B for controlling peak bulk fields and zone JTE_S for controlling peak surface fields. The second approach (**b**) features an epitaxially grown JTE layer, which is partly etched to give JTE_B and JTE_S zones. The third, most successful approach (**c**) uses an improved double-positive-bevel geometry.



tion, or shock)? Since each situation is likely to be different (e.g., near the tower, at midspan, under the line, at the right-of-way edge, in an open field, near a tree), the effect will be different.

To demonstrate the assessment framework, researchers applied it to a sample case. For this hypothetical example, they determined the effects of contact between a farmer and his farm vehicle in the right-of-way of a 550-kV line and also calculated the probability of fuel ignition. For the assumptions selected, the analysis produced the following results.

- Probability of perception = 1 in 510 contacts
- Probability of startle = 1 in 17,500 contacts
- Probability of currents above let-go = 0
- Probability of fuel (gasoline) ignition = 0

These results were then combined with those of the situation analysis to determine how often effects could be expected to occur. For perception effects during contact with the farm vehicle in the right-of-way, the expected frequency of occurrence was calculated to be 1 in 9 years; for startle effects, it was 1 in 300 years.

This method also permits sensitivity analysis. For example, what would be the change if the line were raised 1 foot? In this case the number of perception effects would decrease by 1 every 2 years, and the number of startle effects would decrease by 1 every 26 years. Given this situation, it is possible to determine the cost of one additional startle effect every 26 years.

The project is ongoing; its end product (scheduled to be available in late 1986) is a computer program that will permit the line designer to make a probabilistic assessment for all the usual situations that can possibly lead to an effect. Progress to date includes the probabilistic assessment framework, the sample case, and a preliminary, research-grade computer program. Although the project's results will not be available in user-friendly form until late next year, line designers with in-depth expertise in this area who want to obtain the interim report can do so by contacting the EPRI project manager at (415) 855-2305.

When the computer program is completed, line designers will be able to easily and quickly calculate the probability of induction effects from ac lines and perform sensitivity analysis to compare the cost of proposed line design revisions with the resulting increase or decrease in effects. *Project Manager: John Dunlap*

TRANSMISSION SUBSTATIONS

10-kV light-triggered thyristor

A project is under way to develop new designs and production processes for light-triggered thyristors capable of blocking at about 10 kV (RP2443). Such a device would have the potential to reduce the number of thyristors and associated components by about a factor of two over the present state of the art (4.5-kV rating, 5-kV breakdown voltage) for HVDC and static VAR controls. This would reduce any system's conduction losses. Moreover, the device's light-triggering capability would greatly reduce system gating costs and complexity.

To meet the above objectives, the first major task of this project was the development of a suitable breakdown voltage technology. Specifically, the objective was to develop a process that would enable both forward and reverse breakdown voltage (symmetric) to be at least 90% of the ideal breakdown voltage at any design level. The first attempt at this goal was based on an ion-implanted junction termination extension (JTE), as illustrated in Figure 3a. This work was successful on low-current, small-area devices, but yield losses prevented achievement of the ideal breakdown voltage.

The second attempt to obtain 90% or more of the ideal breakdown voltage also involved the JTE approach, but this time an epitaxial charge control layer was used (Figure 3b). Epitaxy defects present on every wafer reduced the breakdown voltage by about 1500 V in large-area devices.

The third attempt at meeting the 90% level was a new double-positive-bevel geometry, with more silicon material removed from the lightly doped side of the junction (Figure 3c). This approach is very promising and has become the process of choice for the 10-kV light-triggered thyristor project. The success of the double-positive-bevel technique, which will give up to 95% of the ideal breakdown voltage, indicates that the project goal can be achieved, once the proper starting silicon material is received. *Project Manager: Harshad Mehta*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

ENHANCED ACID DEPOSITION DECISION FRAMEWORK (ADEPT)

Concern over the possible impacts of acidic deposition has led to proposals for additional controls of utility sulfur oxide (SO_x) and other emissions thought to be precursors of acidic deposition. EPRI developed the ADEPT model (version 1) under RP2156-1 so utilities and policy makers evaluating these proposals could integrate scientific information and uncertainties related to the transport, conversion, and impacts of acidic deposition with judgments regarding policy costs. Recently enhanced to keep pace with the increasingly complex debate surrounding acidic deposition policy, ADEPT (version 2) now represents nitrogen oxide (NO_x) as well as SO_x emissions, provides for multiple source and receptor regions, and allows more complex descriptions of lake and forest impacts. Applications to date provide strong evidence that ADEPT can serve as a vehicle for developing a consensus about acidic deposition policy issues.

To evaluate alternative control strategies requires an understanding of the relationship between various levels of emission reduction and the impacts of acidic deposition. Policy makers then may weigh the potential changes in impact against the cost of achieving emission reductions. Several factors, however, complicate the comparison of control strategies. For example, a large degree of uncertainty remains about the relationship between emissions and effects. Reducing uncertainty about this relationship requires further scientific knowledge, which will be developed over a period of years; how long the research will take is itself uncertain. In addition, it is difficult to compare the value of changes in impacts with the costs of emission reductions. People involved in assessing control and mitigation strategies assume different degrees of uncertainty and disagree on how to evaluate costs and impacts.

The decision framework implemented in ADEPT allows explicit treatment of each of these factors, separating the evaluation of costs and impacts from the issue of resolving uncertainty over time. The framework provides a vehicle for the discussion and investigation of sensitive assumptions. By identifying the important areas of agreement and disagreement motivating policy decisions on acidic deposition, ADEPT can assist decision makers, facilitate consensus building, and improve the quality of debate.

Structure

The relationship between control alternatives and the impacts of acidic deposition is keyed to three stages: the effect of control strategies on emission levels, the effect of changes in emissions on acidic deposition, and the effect of changes in acidic deposition and of mitigation alternatives on the potential impacts (possibly, for example, decreased forest productivity and the loss of sport fisheries). As shown in Figure 1, ADEPT's decision framework addresses these three stages through its source, transport and conversion, and receptor modules.

Considerable uncertainty exists regarding

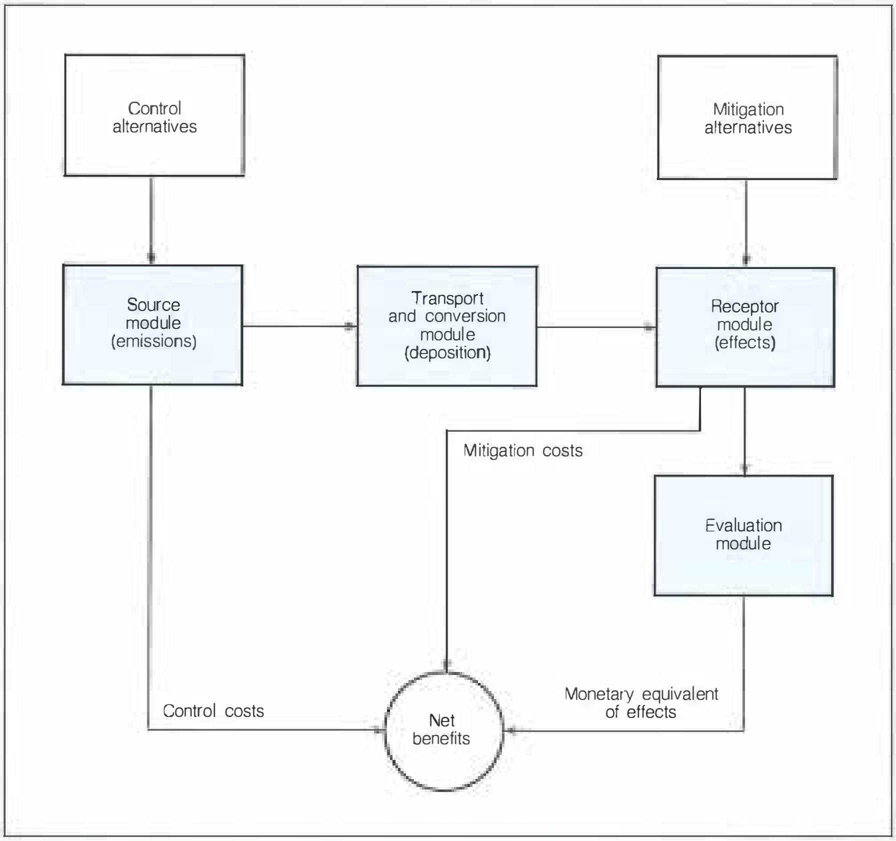


Figure 1 The ADEPT model. The source, transport and conversion, and receptor modules determine the environmental effects of acidic deposition, given a particular control and mitigation strategy. Each of these modules provides for the explicit consideration of uncertainty. The evaluation module then uses value judgments to assess how much the outcome of a particular control and mitigation strategy is worth to society. Thus the benefits of the strategy can be weighed against its costs.

the extent and rate of acidic deposition impacts, the transport of emissions to receptor areas, and the chemical transformations that take place during that transport. Estimates in these areas by respected scientists vary by several orders of magnitude. The first stage, however, which concerns the relationship between control strategies and emission levels, shows somewhat less uncertainty. Accordingly, the importance of uncertainty in the second and third stages has been stressed in implementing the framework.

ADEPT uses decision tree methodology to consider both the available strategies and the resolution of uncertainty at different points in time. A decision tree is simply an efficient way of describing a series of scenarios, each defined by a set of choices and uncertainty outcomes (Figure 2). Thus the ADEPT methodology provides for a time sequence of decision making and uncertainty resolution.

The first two points in Figure 2 represent decisions within the next few years on control and mitigation options and on the funding and direction of acidic deposition research. Next are two points of uncertainty resolution in the late 1980s, when researchers will be obtaining new scientific knowledge on acidic deposition; these uncertainties involve emission levels, the relation of emissions to deposition (i.e., transport and conversion), and the impacts of deposition. Then comes a decision point in the early 1990s, when policy makers can reassess policy on control and mitigation and choose an alternative on the basis of the new information available. The methodology concludes with two points of uncertainty resolution representing long-term research outcomes on transport and conversion and deposition effects.

The decision tree approach provides a useful separation between value judgments on the costs and benefits of a strategy and judgments about the uncertainties in the science of acidic deposition. Each decision tree scenario has consequences for a number of concerned parties: consumers, who may have to pay more for electricity because of decisions to impose controls on power plants; fishermen and recreational property owners, who may be involved if acidic deposition affects sportfishing in a given lake; forest product firms and property owners, who may suffer economic losses if acidic deposition reduces forest productivity; and those members of the general public concerned about possible ecological changes from acidic deposition. The evaluation of these consequences is difficult because the parties involved know that some will bear more of the costs resulting from a particular decision while others will receive more of the benefits.

The political reality is that government officials will decide what trade-offs to make between the costs that one group bears and the benefits that another group receives. Because issues of equity and property rights make such value judgments extremely difficult, it is useful to separate these value judgments from uncertainties about the long-range transport of sulfur and other pollutants and about the effects of acidic deposition. Therefore, the decision framework makes a distinction between the determination of what will happen in various control, mitigation, and uncertainty resolution scenarios and the evaluation of what each outcome is worth to society.

Implementation

The ADEPT computer software implements an acidic deposition decision framework developed by Decision Focus, Inc. The initial version of this model (version 1) was primarily for national or regional use. As state legislatures considered measures to protect sensitive ecological areas within their boundaries, growing interest in adapting the framework for use in state-level analyses led to a revised version of the model (version 1.1). This version was demonstrated in a case study sponsored jointly by EPRI and utilities in Minnesota (EPRI EA-2540, Vols. 1 and 3).

Versions 1 and 1.1 of ADEPT have been available for distribution through the Electric Power Software Center (EPSC) for about two years. The model is available for both mainframe computers and IBM-compatible personal computers. Twenty utilities, seven state or federal government agencies and their contractors, and four universities have copies of the model.

Version 2 of ADEPT, recently released, is available from EPSC for use on mainframe computers and IBM-compatible personal computers. This new version provides many enhancements over earlier versions, expanding the variety and amount of detail available

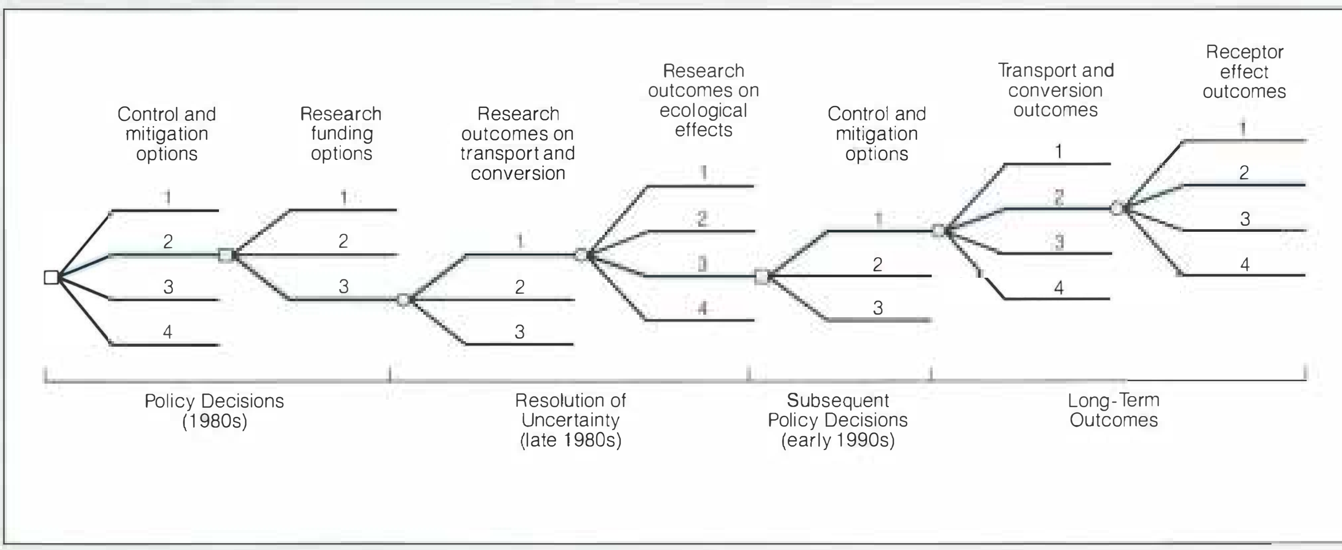


Figure 2 Each ADEPT decision tree scenario leads the user through a sequence of policy decision points (squares) and uncertainty resolution points (circles), with a number of options available at each point. The methodology explicitly includes the option of adopting an acidic deposition control and mitigation strategy now and the option of waiting for better information to become available.

for evaluating acidic deposition policy options. ADEPT now considers both NO_x and SO_x controls and can also represent hydrocarbon controls. In addition, version 2 can model lake and forest impacts as a complex function of deposition that has occurred in previous years, and multiple source and receptor regions can be taken into account.

Several other enhancements make ADEPT more useful for analysis. The model now includes a general capability to add and delete assumptions treated in a probabilistic fashion, and sensitivity analyses can be performed for any assumption. Relations between emissions and deposition and between deposition and impacts are input as easily understood piecewise linear functions. The user also has extensive control over model input and output. For example, input data are organized by tables of data, much as they would appear in a report, and the model reads these tables directly. A notebook function is provided to collect output of interest across several cases. Users have the option of collecting commands for playback, so that standard sets of cases may be automated.

Applications

EPRI's role is limited to model development and testing. The actual application of ADEPT in policy debates is left to the individual user. In one recent application of the model, the Wisconsin Utilities Association used ADEPT to summarize the current state of knowledge regarding the extent and likelihood of impacts of acidic deposition within Wisconsin.

Acidic deposition is regarded as a potentially serious environmental problem in Wisconsin. It has motivated a substantial research effort by the Wisconsin Department of Natural Resources, the Wisconsin Public Service Commission, and the state's electric utilities. Although this cooperative research effort has yielded a great deal of information since its inception in 1981, much uncertainty still remains. Policy makers confront enormous difficulties in comparing the economic and ecological impacts of imposing immediate controls on SO_x emission sources with the potential costs of waiting for further research to resolve uncertainties about what threat acidic deposition poses to Wisconsin's surface waters and forests.

Carried out during a period of two months in early 1985, the Wisconsin application of ADEPT incorporated judgments, obtained from a panel of seven expert scientists, about atmospheric science and the aquatic and terrestrial impacts of acidic deposition. The application illustrates how policy makers can use these kinds of judgments as a basis for comparing emission control policies. Such comparison depends on scientific judgments about the likelihood and extent of ecological damage and on value judgments about the trade-off between acidic-deposition-induced damage and the economic costs imposed by emission control. ADEPT analysis explicitly sets forth both types of judgment, and extensive sensitivity analyses have shown how the relative costs and benefits of alternatives change, depending on the judgment used.

Although there is no definitive evidence that ecological impacts from acidic deposition have occurred in Wisconsin, the members of the expert panel stated that such impacts could happen in the future. They added, however, that the extent and likelihood of the potential impacts are limited. Acidification of up to 15,000 acres of lakes was judged to have a probability of 10%; this area represents about 2% of Wisconsin's lake area. Acidification of a small percentage of headwater streams is also possible, but research in the state has produced little information on streams. Loss of productivity in forest areas on sensitive soil is a remote possibility; a probability on the order of 1% was assessed for productivity declines within the next 50 years affecting up to 10% of Wisconsin's forested land area.

Given the judgments on the likelihood and extent of ecological impacts from acidic deposition in Wisconsin, the ADEPT analysis indicated that the risk of potential resource losses from waiting up to 10 years while conducting research appears to be small. If future research findings indicate that significant ecological damage will result from acidic deposition, policy makers could implement additional emission controls at a later time. Values placed on the sensitive ecological resources in Wisconsin imply a very high benefit to carrying out research to resolve the current scientific uncertainties regarding the potential impacts of acidic deposition on surface waters and forests. *Project Manager: Dennis Fromholzer*

EFFECTS OF ACIDIFICATION ON FISH

Scientists disagree about the extent of fish population losses resulting from acidic deposition. The decision to regulate industrial emissions to prevent such losses hinges largely on questions regarding the causal connection between emissions and the acidification of aquatic environments. Just as important to this decision, however, is an understanding of how fish populations respond to changes in water quality that result from lake acidification. Predicting these responses is critical to assessing the costs or benefits of emission regulation. The goal of EPRI's lake acidification and fisheries (LAF) project is to develop a method to estimate these responses (RP2346).

One approach to determining the relationship between lake acidification and fish population response is to survey the water quality and fisheries status of many lakes over a wide range of acidities (pH levels). Typically, this involves correlating the presence or absence of fish species with water quality conditions to identify the pH thresholds required to maintain fish populations. Although this approach is fairly inexpensive on a per lake basis and rapidly generates data for a wide range of species, it has several drawbacks.

First, single (or limited) samples may not provide a realistic picture of chemistry and biota for a given lake. Such sampling may miss biota present in small numbers, and it ignores the possible importance of episodic acid pulses in affecting the ability of biota to exist in a water body. Second, in assuming water chemistry to be the primary determinant of fish occurrence, the approach disregards physical factors (e.g., the presence of spawning areas) and biotic factors (e.g., the presence of predators) that are known to affect the distribution and density of some fish species. To include these additional factors in analyses calls for increased data and a larger number of sample lakes, raising the survey costs. Third, because this approach does not examine mechanisms, predictions of population response for individual lakes are subject to substantial error, as are regional conclusions based on such predictions.

Researchers on the LAF project are taking an alternative and complementary approach by combining population models and laboratory toxicity data to assess the responses of fish populations to lake acidification. Specifically, they are studying four fish species that are widely distributed in waters sensitive to acidification and that represent a range of acid sensitivities, fish families, and lifestyles. This approach generates data more slowly than the survey approach; however, once it is validated, it has the potential to predict population response to a wide variety of conditions in acid lakes.

The EPRI approach has two disadvantages: in its simplest form it ignores interspecies interactions, and it is applicable to only a few of the important fish species. To compensate for these limitations, three of the fish chosen are "top predators," fish that may be less susceptible to losses of prey because they have the ability to switch to another species for food. In addition, the studies include an investigation of toxicity mechanisms, which may allow results to be generalized to other species on the basis of physiological similarity.

Methodology

The LAF project is a highly integrated effort: although it comprises four distinct tasks, researchers working on one task exchange information with those in the other areas (Figure 3). The project is also coordinated with other work sponsored by EPRI, EPA, the Ontario ministries of Natural Resources and of Environment, and federal and state fisheries agencies in the United States and Canada.

The primary objective of task 1, being conducted by researchers at Oak Ridge National Laboratory in Oak Ridge, Tennessee, is to develop fish population models that simulate the responses of fish populations in acid lakes. (Data for these models are being gathered from both the literature and the field in task 2.) A secondary objective is to develop and apply statistical models to help design the toxicology studies (task 3) and interpret their results.

The conceptual framework for task 1 divides the fish life cycle into three periods—juvenile to adult, reproductive period, and egg to juvenile—based on expected differences in sensitivity to stresses of acidification. Optimal input to the models includes information obtained in tasks 2 and 3 on survival, growth, maturity, and fecundity for fish at each age. The models have two uses: to focus the toxicology studies on critical life stages and hypotheses and to predict relative population responses to specific conditions of pH, aluminum, and calcium. These predictions will be compared with case histories of fish populations in the field.

In task 2 researchers at Western Aquatics, Inc. (WAI), in Laramie, Wyoming, are compiling published and unpublished field data on rates of fish survival, growth, and fecundity for use in modeling populations of the selected species that inhabit sensitive (low-conductivity) lakes.

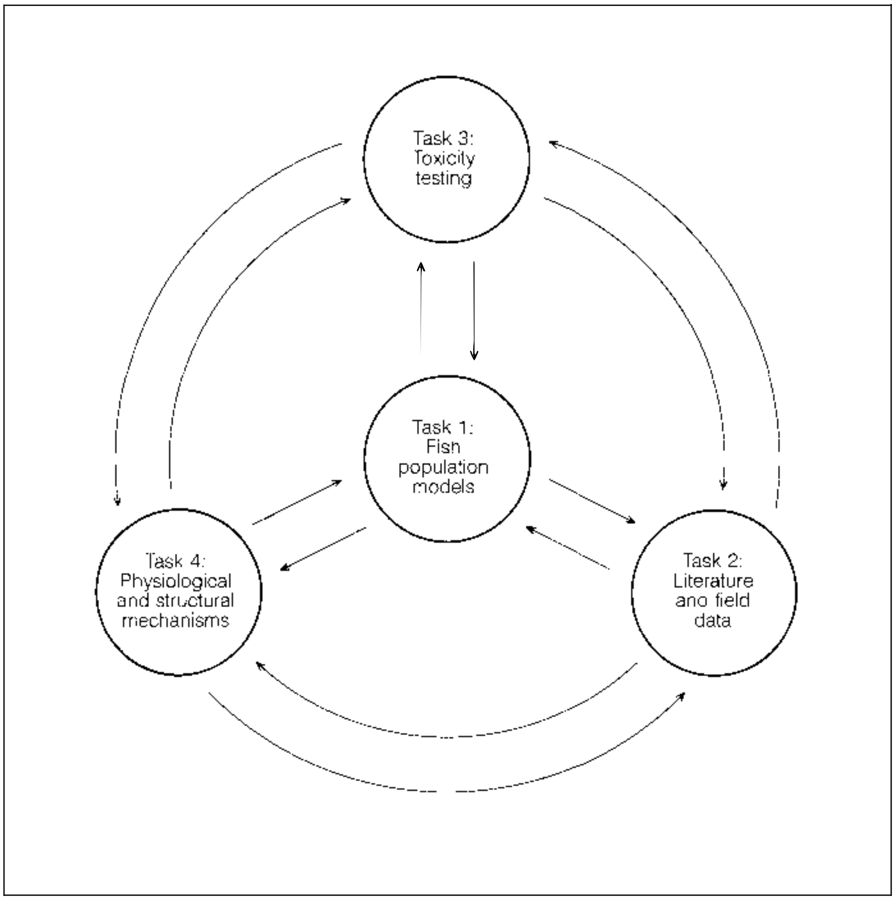


Figure 3 Fish population models provide the focus for internal integration of the LAF project. Feedback loops between the tasks are iterative; for example, the generation of a hypothesis in task 3 may lead to the identification of data needs by task 1 researchers and the collection of such data by investigators in tasks 2, 3, and/or 4.

Such data are required because fish are not as productive in sensitive waters as they are in insensitive (hard water) lakes. The WAI staff is also compiling a compendium of past work on acidification response for each of the LAF fish species.

Task 3 investigators at the University of Wyoming, also located in Laramie, are determining the effects of various levels of pH, aluminum, and calcium on survival, growth, and reproduction at different life stages of each species—for example, brook trout (Figure 4). For early-life-stage studies a full matrix of exposure regimes is being used, including five levels each of pH and aluminum and four of calcium. This is the most extensive matrix ever attempted for simulating water acidification in the laboratory, and it required the construction of a complex dosing system. Further experiments will involve the same or fewer regimes, depending on initial results. Exposure for the early-life-stage studies covers the time from egg fertilization through early juvenile, a period that may last 90 days; during this time hatchability, survival, and growth will be monitored.

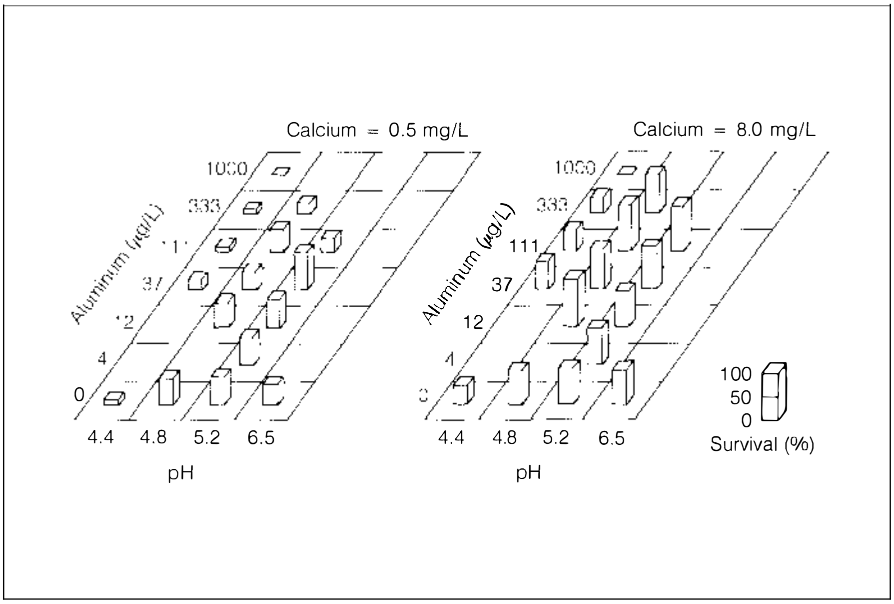
Studies of adults last four to six months to encompass egg production through spawning. In addition to documenting the survival, growth, and reproduction of adults, researchers will expose offspring from previously exposed adults to a limited matrix of pH, aluminum, and calcium to determine whether preexposure influences hatchability or survival.

Data from task 3 will provide the bulk of the information needed to express mortality and fecundity as functions of pH, aluminum, and calcium; the resulting models will be capable of predicting relative population responses to acidification. Both laboratory and field experiments will be conducted to ensure that the laboratory results represent what actually happens in the field. For example, current thought is that aluminum complexes formed with dissolved organic carbon and/or fluoride may reduce the concentration of toxic aluminum. If this is true, measurements of monomeric inorganic aluminum concentrations in natural waters will be sufficient to describe the contribution of aluminum to total toxicity. If laboratory and field toxicity levels differ significantly, however, additional components must be added to the laboratory matrix before users can rely on the model to produce accurate field predictions.

Project investigators at McMaster University in Hamilton, Ontario, and at the University of Wyoming are conducting physiological studies on ionic exchange across gills, blood chemistry, egg production, and structural pathology (task 4). They are searching for

Figure 4 Brook trout are being tested for survival, growth, and reproduction in studies conducted at the University of Wyoming. These studies employ an elaborate dosing apparatus to handle the extensive matrix of exposure regimes.

Figure 5 Brook trout in the eyed-egg stage (about 15 days after fertilization) were exposed to various conditions of pH, aluminum, and calcium for 40 days to observe the toxicity relationships among these factors. The relationships are indeed complex. For example, for both extremes of calcium level shown here, the mean percentage survival at low pH (4.4) is higher in the presence of low aluminum than when no aluminum is present; however, aluminum clearly increases toxicity at higher concentrations.



mechanistic explanations of toxic responses observed in task 3. In these tests fish are exposed to partial matrices of pH, aluminum, and calcium similar to those in task 3 and are then examined for physiological and structural effects. Using this information, researchers may be able to extend the findings for the four LAF project species to other species with somewhat different sensitivities to acidic lake conditions.

Initial results

A model (DELREP) has been developed that incorporates survival, maturity, and fecundity data derived from laboratory studies to predict the effect of water chemistry on the number of a female's offspring that survive to reach the same age as the female at spawning. Sensitivity analyses have indicated that reductions in the survival of yearling and older fish can be more significant than equivalent reductions in fecundity or losses of fish during the first year of life. These findings have reinforced the need for toxicity studies involving fish beyond early life stages, even though the young fish were expected to be more sensitive to pH, aluminum, and calcium.

The project has accumulated over 1800 open and gray literature reports on brook trout, white suckers, and smallmouth bass. Contacts have been made with researchers and with federal, state, and provincial agencies in the United States and Canada to obtain published and unpublished data sets. Together, data from several of the sets appear sufficient for estimating the survival, growth, and fecundity rates required as inputs for the baseline model (sensitive, nonacidic waters).

Several general conclusions can be drawn from the toxicity tests on brook trout (Figure 5). Increased acidity and aluminum reduce hatching success, but calcium does not appear to have much effect on the hatching process. Larval survival at low pH levels is reduced by aluminum and enhanced by calcium. Calcium also enhances larval growth at low pH, but aluminum has little effect. A full 90-day early-life-stage toxicity study starting with freshly fertilized eggs has been completed, and preliminary results indicate that freshly fertilized eggs constitute the most sensitive egg stage. Adult growth and reproductive effects have also been observed at those combinations of pH, aluminum, and calcium that reduce egg and larval survival and growth.

The most progress on task 4 (physiology) has been made in the area of ionoregulation. For brook trout, aluminum at concentrations near 100% saturation causes large net losses of both sodium and chloride; net losses are reduced, as is mortality, when pH falls or calcium rises. Aluminum toxicity appears to be related to precipitation of aluminum hydroxides on the gills, but further work is required to determine if this is the cause of the ion losses. Samples collected for structural pathology and reproductive physiology studies are currently being analyzed.

Implications

The LAF project is establishing an extensive data base that documents toxicological and physiological effects of acidity, aluminum, and calcium on sensitive life stages of four important fish species. Once the laboratory toxicity data have been field-validated, the toxicity data will be incorporated into mathematical population response models for these species. After field calibration, the models could be used to predict the responses of fish to both increases and decreases in lake acidity. Results from this project, along with data documenting the response of lakes to different levels of acidic deposition on watersheds and the influence of emissions on deposition, will help decision makers compare the costs and benefits of emission management options.

Initiated in late 1983, this project is scheduled for completion at the end of 1988. Reports presenting the results for brook trout could be available as early as the spring of 1986. *Project Manager: J. S. Mattice*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

HUMAN FACTORS
CONTROL ROOM DESIGN

Applying human factors criteria and principles in designing a nuclear power plant can reduce human error and improve plant safety and availability. Research by EPRI and others has identified areas in which an appropriate consideration of human factors during plant development can improve plant design (e.g., EPRI NP-309, NP-1118, NP-1567, and NP-2035). In the important area of control room design, EPRI has developed integrated, specific guidelines for ensuring the systematic implementation of human factors principles and practices. These guidelines, which are presented in NP-3659, can be used both in designing control rooms for future plants and in backfitting existing control rooms.

The accident at Three Mile Island, which was thoroughly documented in the Kemeny commission's report, focused attention on human factors issues and problems. Not since the early years of the space age has there been such interest in this area. After TMI, the NRC issued two regulations dealing with control room review and backfitting, NUREG 0700 and 0801, and EPRI published a human engineering guide for enhancing existing control rooms (NP-2411) that complemented the NRC regulations. NP-3659, the new guide described in this report, extends previous work by integrating into one source human factors principles and criteria for the design phase of a nuclear plant. Most of the material in the guide also applies to fossil fuel plants, despite some differences in the problems encountered in the two types of plants (e.g., radiation exposure in nuclear plants, coal dust and fly ash problems in fossil fuel plants).

Focusing on operator performance requirements in the control room, the guide seeks to relieve personnel of unnecessary tasks, reduce the potential for human error, and identify design features that are compatible with innate human capabilities and limitations. Since backfitting is very expensive and poses special problems of implementation in a spatially fixed environment, the most cost-effective, technically efficient approach is to apply human factors principles and criteria throughout the plant development process. The earlier in the design phase human factors are considered, the more efficient will be the final result.

The guide is a comprehensive reference document that will enable a design team (preferably a multidisciplinary one with human factors representatives) to weigh the advantages and disadvantages of alternative design approaches and to make the many trade-offs that characterize the design process. Also, by enabling the team to apply scientific knowledge gained from empirical research on human performance requirements in the man-machine interface, the guide helps to maximize system effectiveness and minimize operator and system error in normal and emergency operating situations.

To ensure the guide's usefulness in nuclear power plant design (and operations), EPRI established these criteria: it must be complete with respect to the human factors trade-offs and decisions made throughout the plant design, development, and operations cycle; it must be authoritative and up-to-date; and it must be helpful and easy to use for all the engineers, operators, specialists, human factors engineers, and managers involved in the development process. To meet these objectives, a multidisciplinary approach was followed in determining the guide's content and format.

Representatives from utilities, nuclear steam supply system vendors, and power industry and architect-engineering consulting firms helped identify critical plant development processes and trade-off decisions involving human factors. After a prototype guide was developed, members of the potential users' population attended a workshop and used the guide to resolve simulated design and evaluation problems. They reviewed drafts produced by the project team and contributed specific suggestions for improvement.

The participants in the review process found the guide to be technically accurate, comprehensive, and useful for its intended audience. To illustrate its scope, here are some of the functions the guide performs.

- Presents step-by-step guidance for structuring a human factors program plan
- Outlines an approach for describing and analyzing plant functions and systems and operator tasks
- Provides guidance regarding control room layout, environmental conditions, and habitability
- Makes recommendations about defining display and control instrument requirements, arranging instruments on panel surfaces, and applying labeling, demarcation, and coding techniques
- Describes preferred display and instrument room features
- Presents design support guidelines for an integrated communications system and for alarm and annunciator systems
- Describes techniques for use in the design verification and validation phase (e.g., walk-throughs, models, and full-scale mock-ups)
- Provides anthropometric design criteria and a brief review of basic human capabilities (i.e., sensing, processing, remembering, and responding)

In addition, the guide contains a glossary, extensive illustrations, a checklist at the end of each technical chapter, and a comprehensive cross-referenced subject index.

The guide has been published in two versions: a loose-leaf edition prepared primarily for electric utilities and a bound edition for the human factors and academic communities. To ensure the guide's continued usefulness, the loose-leaf version will be periodically updated on the basis of comments and recommendations from users and the results of ongoing research. EPRI invites utilities to participate in evaluating the guide when they design or modify control rooms, and solicits feedback on improving its coverage and content. *Project Manager: H. L. Parris*

IN-REACTOR SOURCE TERM EXPERIMENTS

The source term represents the amount, type, and timing of predicted radiation release in a reactor accident. There is evidence that experts have overpredicted the consequences of many low-probability nuclear reactor accidents and hence their radiation release. Overprediction results in overplanning for emergency response and an unnecessarily negative public perception of potential reactor accident outcomes. The key to realistic prediction of accident consequences is prediction of a realistic source term. An EPRI test program studying volatile fission products is being carried out to improve the accuracy of such predictions (RP2351).

Source term analysis requires a good understanding of a fuel's nuclear isotope inventory, aerosol formation and chemical behavior, aerosol release rates, and the timing of events that affect these processes. Current consequence analyses begin with assumed aerosol particle size distributions based on expert judgments that have not been validated by experiments. Computer codes treat the chemistry of the aerosols produced in the nuclear core during a severe accident as approximations, which also have not been validated.

To fill this gap in knowledge, EPRI began the source term experimental program (STEP) under RP2351. The objective is to conduct in-reactor experiments on the behavior of volatile fission products (usually the major contributors to risk) for conditions representative of risk-dominant severe accident sequences. The project will provide data for validating the volatile-fission-product characteristics assumed by experts in predicting the consequences of severe accidents and for validating such computer codes as RAFT (reactor aerosol formation and transport), which is being developed by EPRI under RP2135-11.

This project will also yield some supporting data about the timing and extent of hydrogen generation, the timing of fuel degradation, the release of volatile fission products, and the behavior of control rods during severe accidents. Data from these experiments should also help validate the assumptions inherent in all source term ex-pile aerosol tests—that is, that the particle size distribution and chemistry of aerosols generated in ex-pile tests are similar to those that will occur in a reactor.

The tests are carried out in an in-pile test unit (Figure 1). Each test section of the unit contains four irradiated fuel rods, which were provided to STEP by two cosponsoring organizations, the U.S. NRC and Belgonucléaire of Belgium. The fuel rods have a burnup of 30,000 to 40,000 MWd/t and are from the set of rods used in the NRC's severe fuel damage experiments conducted at the Power Burst Facility. Steam enters the bottom of the test unit from a supply located in an auxiliary box on the top of the reactor. A zirconia flow tube acts as an insulator around the fuel rods, which are expected to reach temperatures in excess of 2033 K (3200°F).

A "sample tree" is suspended over the fuel in a plenum region of the test assembly. The tree has three sampling locations: lower (above the fuel and opposite the entrance to the lower aerosol characterization canister), middle (in the middle of the plenum), and upper (opposite the entrance to the upper aerosol characterization canister). Each location has 16 coupons, which comprise a mixture of material samples (silver, alumina, oxidized carbon steel, Inconel, palladium, platinum, and zirconium) designed to allow deduction of the aerosol and fission-product chemistry during the test.

An effluent filter is used to trap the majority of released fission products to allow straightforward post-test handling of the test unit and the auxiliary box. Each aerosol canister, which is designed as an elutriator (settling vessel), has three chambers. By manipulating valves in the auxiliary box, researchers can direct the aerosol flow into different chambers during dif-

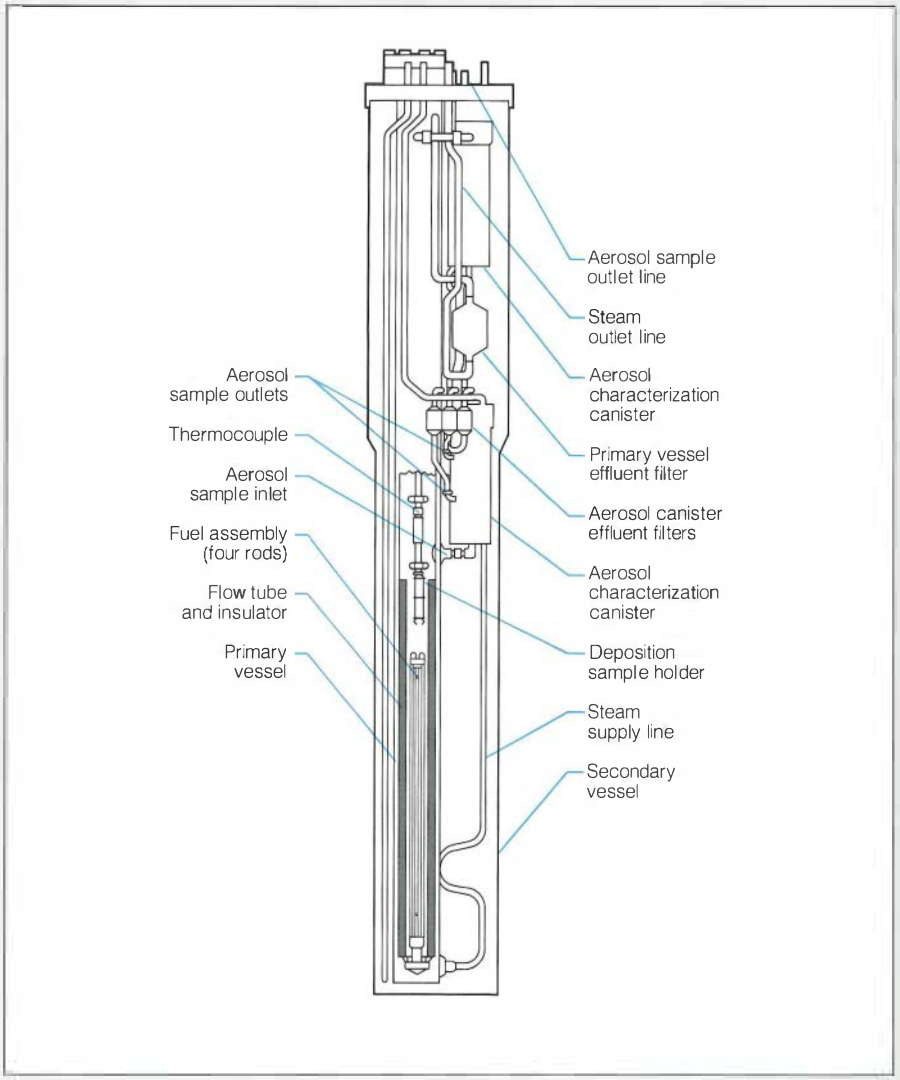


Figure 1 Diagrammatic view of the in-reactor test unit. Steam enters through the steam supply line and travels within the flow tube past four nuclear fuel rods. The flow tube is surrounded by a zirconia insulator to allow the test unit to withstand temperatures of 4040°F (2500 K). Aerosol is generated in the fuel region and flows past the sample holders on the sample tree, out the primary vessel, through the effluent filter, and up to a receiver tank (not shown) at the top of the reactor. A portion of this flow is split off and diverted through the two aerosol characterization canisters. Flow through three chambers in each canister is controlled by the experimenter to allow time-dependent (sequential) sampling of the effluent.

Figure 2 The first stage of a chamber in the STEP-1 upper aerosol characterization canister (a chamber that sampled throughout the test) includes two fine-wire impactors that have been covered with aerosols (light-colored material). The aerosol stream entered this stage from above, and an impaction shadow appears at the left, just in front of the large hole (which contained a tube to carry the aerosol stream to other chambers). Almost hidden at the lower right is the exit hole to the chamber's next (lower) stage.

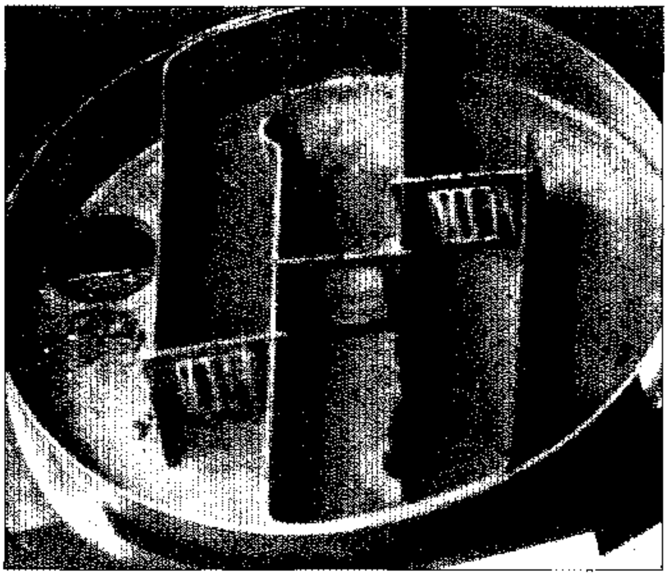
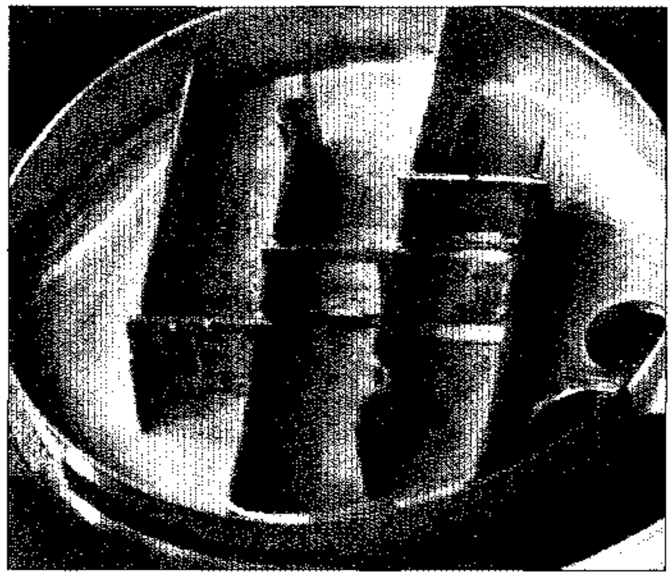


Figure 3 The second stage of a different chamber in the STEP-1 upper aerosol characterization canister (a chamber that sampled for only the first half of the test period) shows less aerosol loading. A scanning electron microscope sample collector can be seen on the floor of this stage to the right, just downstream from one of the open (blank) frames. This collector was oxidized carbon steel cut from a reactor pipe provided by Ontario Hydro, a project cosponsor.



ferent portions of the experiment. This flexibility allows time-dependent sampling of the aerosol emanating from the fuel during the latter stages of the test. The elutriators capture larger particles near the inlets and smaller particles farther down their 3-m length. Fine-wire impactors and scanning electron microscope (SEM) sample collectors similar to those on the sample tree are scattered throughout the length of each chamber. Aerosol filters in the sample line, one for each chamber, are downstream of the canisters to catch aerosol particles too small for the elutriators.

Researchers inserted the unit into the Idaho TREAT reactor, which is operated by Argonne National Laboratory for DOE, a project cosponsor. The reactor is programmed to deliver energy to the highly irradiated fuel, which is in a flowing-stream atmosphere. The project team selected four accident scenarios and varied the heat-up rate, system pressure, and control rod material for the different scenarios. The four planned tests have now been run, and the researchers are analyzing the data collected.

The first STEP test was a simulation of a PWR unterminated large-break LOCA (WASH-1400: AD). This test was run at a pressure of 45 psia (0.31 MPa), with steam velocity varying from 5.5 to 1.9 lb/h (0.69–0.24 g/s) and a temperature ramp rate of 5.4°F/s (3 K/s). The thermal response was as expected, and the filter captured appreciable fission products. SEM and microprobe examination revealed significant tin deposits on the effluent filter in addition to the expected cesium and iodine. Zircaloy contains about 1.5% tin. Investigators hypothesized that the local oxidizing Zircaloy attains a temperature adequate to vaporize the tin, which then condenses to droplets in the steam-hydrogen flow stream. The presence of tin suggests that larger particle sizes than previously expected might be observed in the fission-product aerosol, because the tin may act as a seed for condensation of the volatile fission products as they are released from the fuel.

The second STEP test was a simulation of a BWR feedwater failure transient with the concomitant failure of core makeup water systems and residual heat removal systems (WASH-1400: TQUW). This test was run at a pressure of 25 psia (0.17 MPa), with steam velocity varying from 2.7 to 1.8 lb/h (0.34–0.23 g/s) and a temperature ramp rate of 4.3°F/s (2.4 K/s). The third test simulated the loss of all ac power and of reactor coolant system heat removal in a PWR (WASH-1400: TMLB′), and the fourth was a TMLB′ simulation with control rods in place. These last two tests were run at 1130 psia (7.8 MPa), with steam velocity varying from 4.3 to 1.9 lb/h (0.54–0.24 g/s) and a planned temperature ramp rate of 1°F/s (0.6 K/s). Although analysis of the experimental results has not yet been completed, evidence at this time indicates that the tests may yield significant information on the behavior of volatile-fission-product aerosols.

Recently, researchers disassembled the two aerosol canisters from the first STEP test in a hot cell to examine the three chambers in each canister. Each chamber contains 14 separate stages that form a mazelike path for the aerosol to traverse. For the first stage of one chamber in the upper aerosol characterization canister (Figure 2), the radiation reading taken 5½ months after the STEP-1 test was 1700 mR/h (at 15.24 cm); for the second stage of a different chamber (Figure 3), which sampled for only the first half of the test, the reading was 500 mR/h (at 15.24 cm). These figures are the first STEP photographs of aerosols characteristic of severe accidents.

The emphasis of the STEP tests is on determining the aerosol size distributions and chemistry of volatile fission products, primarily cesium, iodine, and tellurium. During the coming year, data analysis is expected to provide insight into the character of nuclear aerosols generated under prototypical conditions for hypothetical severe accidents. Acquiring this information will be a key step in validating computer codes, verifying assumptions made in earlier studies, and validating assumptions inherent in all source term ex-pile aerosol tests. *Project Manager: Richard Oehlberg*

New Technical Reports

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

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

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ADVANCED POWER SYSTEMS

EDS Coal Liquefaction Process Development: Phase 5
AP-3922 Final Report (RP778); Vol. 1, $19.00; Vol. 2, $16.00
Contractor: Exxon Research and Engineering Co.
EPRI Project Manager: N. Hertz

Coal-Fired Combustor Particulate Measurements
AP-3932 Final Report (RP1345-4); $11.50
Contractor: TRW Energy Development Group
EPRI Project Manager: A. Cohn

Workshop Proceedings: Direct Coal-Fired Combustion Turbines
AP-3939-SR Proceedings; $31.00
EPRI Project Manager: A. Cohn

Studies on Water-Steam Rankine-Cycle Solar Central Receiver Power Plants
AP-3982 Final Report (RP1990-2); $19.00
Contractor: Bechtel Group, Inc.
EPRI Project Manager: S. Kohan

Fate of Basic Nitrogen Solvents in Coal Liquefaction
AP-4026 Final Report (RP2147-2); $13.00
Contractor: Virginia Polytechnic Institute and State University
EPRI Project Manager: L. Atherton

Laboratory-Scale Study of the Combustion of Coal-Derived Liquid Fuels
AP-4038 Final Report (RP1412-6); $17.50
Contractor: Massachusetts Institute of Technology
EPRI Project Manager: W. Rovesti

COAL COMBUSTION SYSTEMS

Characterization of Utility Low-Volume Wastes
CS-3737 Final Report (RP2215-1); $13.00
Contractor: Radian Corp.
EPRI Project Manager: R. Komai

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CS-3807 Final Report (RP1263-16); $16.00
Contractors: Leland D. Attaway & Associates; American Technology Management Consultants
EPRI Project Manager: R. Komai

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CS-3844 Final Report (RP1689-5); $14.50
Contractor: Heat Transfer Consultants, Inc.
EPRI Project Manager: R. Coit

Dewatering to Stabilize Fly Ash Disposal Ponds
CS-3863 Final Report (RP1260-36); $16.00
Contractor: Pennsylvania Electric Co.
EPRI Project Manager: D. Golden

Site Evaluation of Failure Data Sheets for Flue Gas Desulfurization Components
CS-3952 Final Report (RP1872-3); $11.50
Contractor: Bechtel Group, Inc.
EPRI Project Manager: T. Morasky

Evaluation of a 2.5-MW Spray Dryer–Fabric Filter SO_2 Removal System
CS-3953 Interim Report (RP1870-3); $25.00
Contractor: Radian Corp.
EPRI Project Manager: R. Rhudy

Field Evaluation of a Utility Spray Dryer System
CS-3954 Final Report (RP1870-4); $22.00
Contractor: Radian Corp.
EPRI Project Manager: R. Rhudy

Regenerable Cement Sorbent for Recycle Fluidized-Bed Combustion Systems
CS-3968 Final Report (RP1179-15); $8.50
Contractor: Associated Universities, Inc., Brookhaven National Laboratory
EPRI Project Manager: S. Ehrlich

Boiler Tube Failures at New Boston: A Root-Cause Analysis
CS-3969 Final Report (RP1711-1); $17.50
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EPRI Project Manager: A. Armor

Intake Research Facilities Manual
CS-3976 Final Report (RP2214-3); $20.50
Contractor: Lawler, Matusky & Skelly Engineers
EPRI Project Manager: W. Micheletti

Proceedings: 1983 Fossil Plant Cycling Workshop
CS-3979 Proceedings (RP1184-5); $43.00
Contractor: Delian Corp.
EPRI Project Manager: F. Wong

Characterization of Steam Cycle Chemistry at Southern California Edison Steam Plants
CS-4005 Final Report (RP1408-3); $20.50
Contractor: Southern California Edison Co.
EPRI Project Manager: B. Syrett

Proceedings: 1983 Fossil Plant Heat Rate Improvement Workshop
CS-4014 Proceedings (RP1403-3); $35.50
Contractor: Delian Corp.
EPRI Project Manager: F. Wong

Performance of a Steam Condenser for Dry Cooling
CS-4016 Interim Report (RP422-2); $11.50
Contractor: Union Carbide Corp.
EPRI Project Manager: J. Bartz

ELECTRICAL SYSTEMS

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EPRI Project Manager: N. Balu

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EL-3918 Proceedings (RP134-1); $19.00
Contractor: National Bureau of Standards
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EPRI Project Manager: F. Garcia

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EL-3977 Final Report (RP7832-3); Vol. 1, $10.00; Vol. 2, $14.50
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Contractor: Ohio State University
EPRI Project Manager: J. Dunlap

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EPRI Project Manager: T. Rodenbaugh

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EPRI Project Manager: E. Norton

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EPRI Project Manager: H. Songster

ENERGY ANALYSIS AND ENVIRONMENT

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EPRI Project Manager: G. Hilst

Plume Model Validation and Development Field Measurements: Moderately Complex Terrain Site
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EPRI Project Manager: G. Hilst

Plume Model Validation and Development Project: Differential Absorption Lidar Measurements of SO_2 in Moderately Complex Terrain
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EPRI Project Manager: G. Hilst

Operational Validation of Gaussian and First-Order Closure Plume Models at a Moderately Complex Terrain Site
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EPRI Project Manager: G. Hilst

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EA-3898 Interim Report (RP934-1, -2); $11.50
Contractors: Bioconcern; IIT Research Institute
EPRI Project Manager: R. Patterson

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Contractors: Angel Economic Reports; Heberlein-Baumgartner Research Services
EPRI Project Manager: K. Miller

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EPRI Project Manager: A. Faruqui

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Contractor: JBF Scientific Corp.
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NUCLEAR POWER

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NP-3789 Final Report (RP1250-3); $23.50
Contractor: S. M. Stoller Corp.
EPRI Project Manager: D. Franklin

Proceedings: Second EPRI Workshop on Support-Structure Corrosion in Nuclear Plant Steam Generators
NP-3924-SR Proceedings; $44.50
EPRI Project Manager: C. Shoemaker

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NP-3927 Final Report (RP2231-1); $14.50
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Extending BWR Fuel Channel Lifetimes: Development of Predictive Deformation Models
NP-3937M Final Report (RP1943-1); $10.00
Contractor: Dominion Engineering, Inc.
EPRI Project Manager: J. Santucci

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NP-3940 Final Report (RP2296-4); $11.50
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EPRI Project Manager: C. Wood

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NP-3941 Interim Report (RP2232-4); $13.00
Contractor: Odetics, Inc.
EPRI Project Manager: F. Gelhaus

Analysis of Refueling Outages in PWRs of Westinghouse Design
NP-3942 Final Report (RP1393-8); $10.00
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: F. Gelhaus

Postaccident Krypton-85 Releases and Control at Nuclear Power Plants
NP-3948 Final Report (RP1560-2); $11.50
Contractor: Science Applications International Corp.
EPRI Project Manager: M. Naughton

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NP-3949M Interim Report (RP1166-1); $8.50
Contractor: Ohio State University
EPRI Project Manager: D. Cubicciotti

TEMPEST Code Simulations of Hydrogen Distribution in Reactor Containment Structures
NP-3955 Final Report (RP1932-16); $10.00
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: J. Haugh

Hydrogen Water Chemistry for BWRs
NP-3959M Interim Report (RP1930-1); $10.00
Contractor: General Electric Co.
EPRI Project Managers: M. Fox, R. Jones

CEPAN Method of Analyzing Creep Collapse of Oval Cladding
NP-3966 Final Report (RP2061-6), Vol. I; $11.50
Contractor: Combustion Engineering, Inc.
EPRI Project Manager: D. Franklin

Crack Growth Rates in Type-304 Stainless Steel in Simulated BWR Water
NP-3970M Interim Report (RP1166-1); $10.00
Contractor: Ohio State University
EPRI Project Manager: D. Cubicciotti

Analysis of the Hydrogen Burn in the TMI-2 Containment
NP-3975 Final Report (RP2168-1); $11.50
Contractor: Factory Mutual Research Corp.
EPRI Project Manager: J. Haugh

PLANNING AND EVALUATION

1985–1989 Research & Development Program Plan
P-3930-SR Special Report; $10.00
EPRI Project Manager: J. Arcella

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