Informing the Global Climate Debate

Also in this issue

- *Renewables*
- *Reducing Radiation Fields*
- *Air Toxics*

ELECTRIC POWER RESEARCH INSTITUTE

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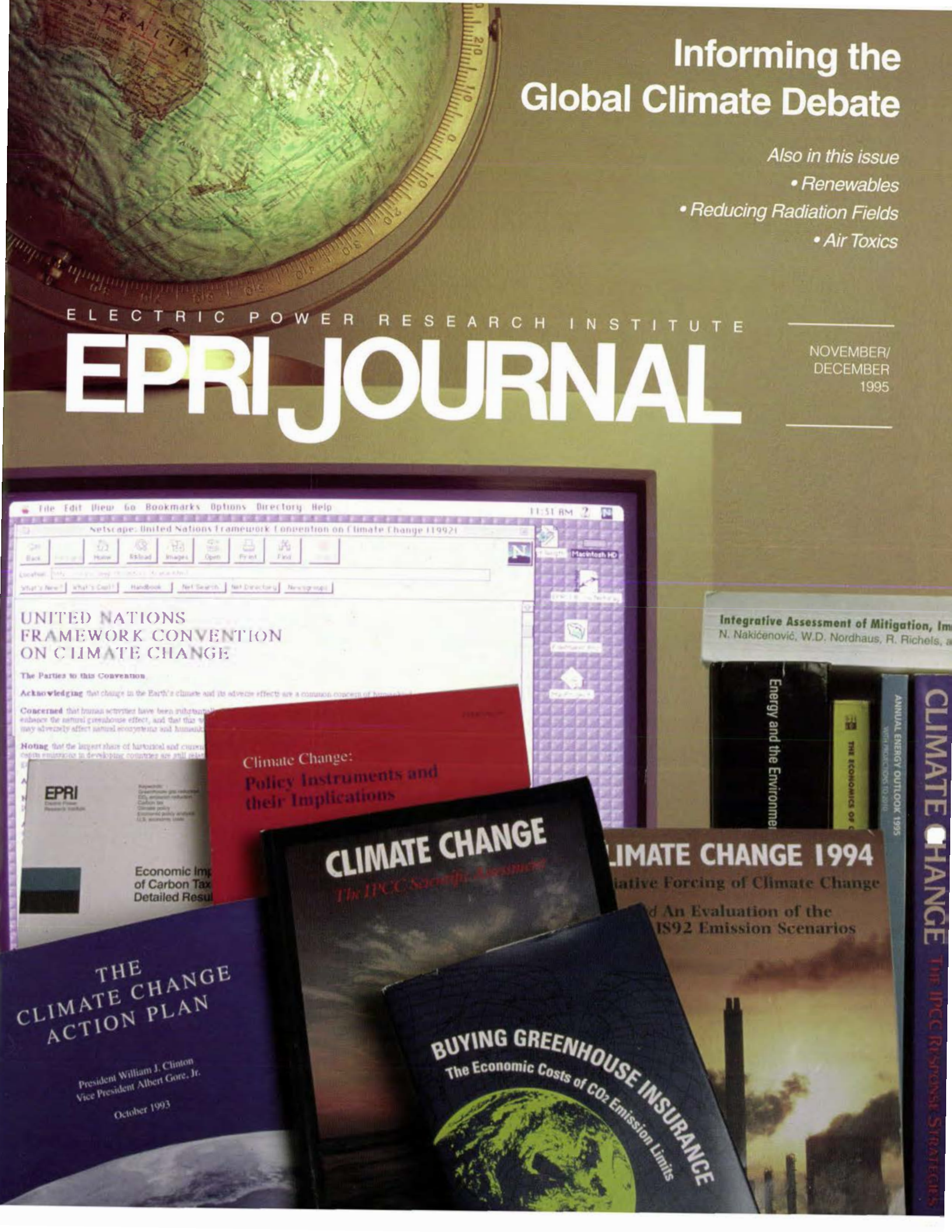

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Cover. Solid science and economic analysis are prerequisites for developing cost-effective national and international policies on climate change.

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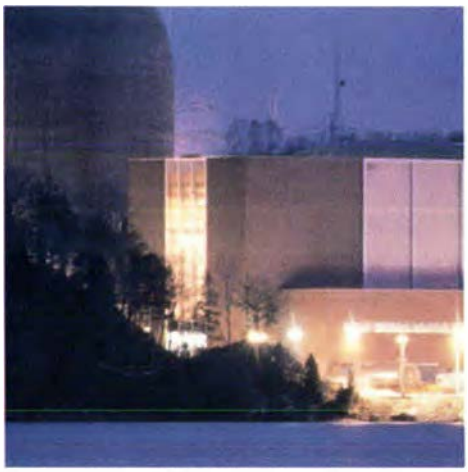
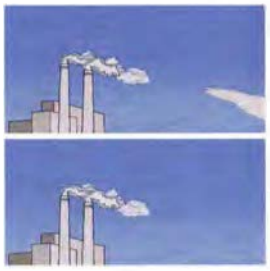


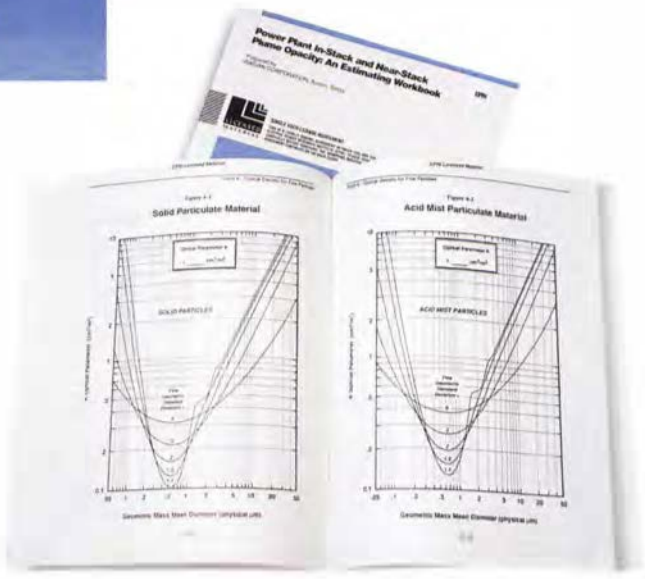
26 Decontamination

Power Quality Guide

Given the increased use of electronic equipment that is sensitive to electrical disturbances, power quality is a critical concern for electric utilities, building owners, and end users. This two-volume guide (TR-101536) was written to help electrical contractors understand and avoid power quality problems as well as respond to such problems when they arise. Volume 1 offers an overview of facility wiring and the electrical distribution system, basic explanations of typical electrical disturbances and their sources, a description of the loads susceptible to various disturbances, and information on relevant codes and standards. Volume 2 covers recommended practices for wiring and grounding to prevent power quality problems, describes effective mitigation devices, provides advice on how to conduct an on-site survey, and discusses maintenance requirements to ensure good power quality.

For more information, contact Marek Samotyj, (415) 855-2980. To order, call the EPRI Distribution Center, (510) 934-4212.





Plume Opacity Workbook

Visible power plant stack exhaust has become a concern for the utility industry. Indeed, some units have been cited even though their particulate mass emissions have been within regulated limits. Contributors to plume opacity include scrubber-generated particulates; condensable particulate matter, such as sulfuric acid in the flue gas; fine particulates that pass through the particulate control device; and colored gases, such as nitrogen dioxide, in the flue gas. This workbook (TR-104425) contains a simplified methodology for estimating the impact of each of these potential contributors. The methodology, which can be implemented with a pencil and a handheld calculator, enables utilities to analyze new and existing plants for opacity problems without the need for extensive, costly plant measurements.

For more information, contact Richard Rhudy, (415) 855-2421. To order, call the EPRI Distribution Center, (510) 934-4212.

Job Cards

A handy reference for nuclear plant mechanics and maintenance personnel responsible for diagnosing and troubleshooting equipment problems, maintenance job cards (published as TR-104602) are chock-full of task-specific reminders. The cards measure about 5 inches square and present concise guidance in seven categories, ranging from valve maintenance to V-belts and sheaves. Hundreds of utility workers are already relying on the cards for instant access to information they would otherwise have to locate in documents beyond the immediate work area. Use of the job cards has proved that they can save time and money, decrease errors, and promote safe work practices.

For more information, contact Ken Barry, (704) 547-6040. To order, call Linda Suddreth at the Nuclear Maintenance Applications Center (NMAC), (800) 356-7448.

Biopower

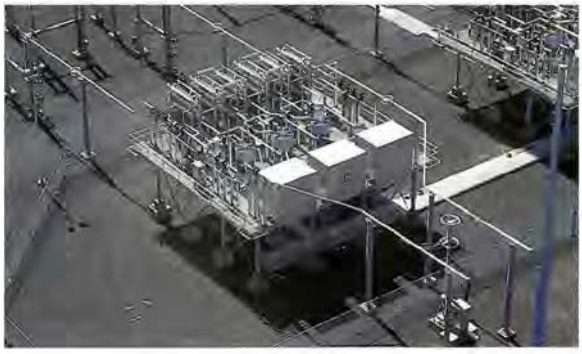
Power system planners and other energy analysts often encounter conflicting, inconsistent data on the cost and performance of biomass and waste-fired generation technologies. In order to provide more consistent and objective data, EPRI developed the BIOPOWER code. BIOPOWER provides plant performance and cost models that enable users to analyze eight different fuel and power plant combinations, including cofired utility boilers; dedicated mass-burn, stoker, and fluidized-bed boilers; and wood gasification technology. Wood, municipal refuse, and scrap tires are just some of the fuels that can be assessed. Users can customize the models to generate process performance and cost estimates for specific fuel properties, unit size, and other design and economic parameters.

For more information, contact Chuck McGowin, (415) 855-2445. To order, call the Electric Power Software Center, (800) 763-3772.

Thyristor-Controlled Series Capacitor

The first in a new generation of transmission controllers, the thyristor-controlled series capacitor (TCSC) represents a significant advance in the control and flexibility of electric power transmission systems. Developed by EPRI in collaboration with the Bonneville Power Administration, the TCSC can be used to direct the flow of electric power more precisely along specific transmission lines and to swiftly stabilize power swings caused by short circuits and other disturbances. To achieve this greater control and efficiency, the TCSC uses advanced solid-state switches. Compared with the conventional equipment on utility transmission lines, the device makes it possible to achieve a much higher level of compensation and power transfer.

For more information, contact Ben Damsky, (415) 855-2385. To order, contact Richard Dube at General Electric, (518) 746-5711.



Dark-rumped petrel

Radar Helps Resolve Seabird–Power Line Dilemma

When the Kauai Electric Division of Citizens Utilities first proposed (in 1989) building a 69-kV power line to improve the reliability of electricity service to Kauai's north shore, area residents and environmental groups mounted concerted opposition because of the possibility that the line might threaten two species of endangered seabirds. Specifically, there was concern that Newell's shearwaters and dark-rumped petrels would collide with the new line or other utility structures as they flew toward the sea from their nests on land. Kauai has one of the largest populations of these birds remaining in the world.

Eventually agreement was reached to launch a three-year research project with EPRI to study the causes and prevention of seabird "fallout" in the area. Fallout is the term used to describe the interruption of flight by collision, exhaustion, or disorientation. As part of this research, two specially modified marine radar units were used to track the birds in flight. The initial results were surprising: virtually all the seabirds were flying at much higher altitudes than previously believed, well above the height of power lines. Equally important, night lighting was identified as a key variable in seabird fallout. The radar revealed that no birds flew under unlighted sections of existing lines, while a few were found under lighted sections.

A second part of the project looked at the ecology and bird population dynamics of the area. While confirming that there are significant threats to these bird populations, both parts of the study indicated that the problem of bird mortality on Kauai is due more to the island's development in general than to the presence of utility structures in particular.

As a result, the project's scientific advisory panel made recommendations regarding predator control and lighting in addition to power line modification. Specifically, the panel recommended establishing an economically and socially acceptable control program for rats, cats, and owls; modifying the intensity or timing of street lamps and outdoor hotel lights, which seem to disorient fledglings on their maiden flight out to sea; and planting trees near power lines, marking the lines with large orange balls or other visual distractions, or even changing line configuration, height, and placement in areas with potentially high collision rates.

Kauai Electric is currently working with Hawaii's Division of Land and Natural Resources on a mitigation program involving such measures. Meanwhile, construction of the new power line has been deferred in favor of rebuilding an existing 12-kV line and adding a new substation on Kauai's north shore.

"The Kauai experience has shown how utilities can work together with concerned citizens' groups on solutions to potential problems involving endangered species—solutions that protect the species while still letting the utilities serve their customers," says project manager Myra Fraser. "This project is just one of several that EPRI has conducted over the years related to bird–power line interactions, and I hope that utilities will continue to seek our help in this sensitive area." ■ *For more information, contact Myra Fraser, (415) 855-2507.*

Newell's shearwater

Atmospheric Oxidants: The Regional Connection

Current regulatory strategies to control ozone pollution in the atmosphere over many cities have focused almost exclusively on reducing localized, anthropogenic sources of precursor gases, such as volatile organic compounds (VOCs) and nitrogen oxides (NO_x). When exposed to sunlight, these precursors undergo photochemical reactions that transform them into ozone and other oxidant pollutants. Many scientific issues surrounding the production and accumulation of such oxidants remain unresolved, however, and recent research has indicated that regional, rather than localized, mitigation strategies will be required to bring some urban areas into compliance with national ozone standards.

There are two main complications: ozone and its precursors can be transported long distances by winds above the ground; and to a large extent, the precursor gases originate as emissions from natural sources, such as vegetation. As a result, more than half of the ozone that contributes to peak urban levels in some areas may come from widely dispersed regional sources. This problem is particularly acute in parts of the South, where intense sunlight, abundant natural precursor emissions, and stagnant summer weather conspire to enhance ozone production and accumulation. Computer simulations have indicated that in Atlanta, for example, a 90% reduction in local NO_x emissions would be necessary to bring the area into compliance with ozone standards, and that even a 100% reduction of anthropogenic VOCs would not achieve compliance. However, the validity of such mathematical models has been called into question by new research findings.

The interaction of regional and urban atmospheric factors governing ozone concentrations has become a major focus of the Southern Oxidants Study, cosponsored by EPRI. Last summer, the study began conducting one of the most comprehensive air pollution field studies ever attempted, focusing on ozone in the Nashville–middle Tennessee area. This area, which has yet to attain the national ozone standard, is particularly well suited for such a study because it is isolated from other urban areas. A primary objective of the work is to improve the ability of mathematical models to simulate regional ozone production and its influence on urban ozone levels, thus providing a tool for studying more-effective mitigation alternatives.

■ *For more information, contact Alan Hansen, (415) 8552738.*

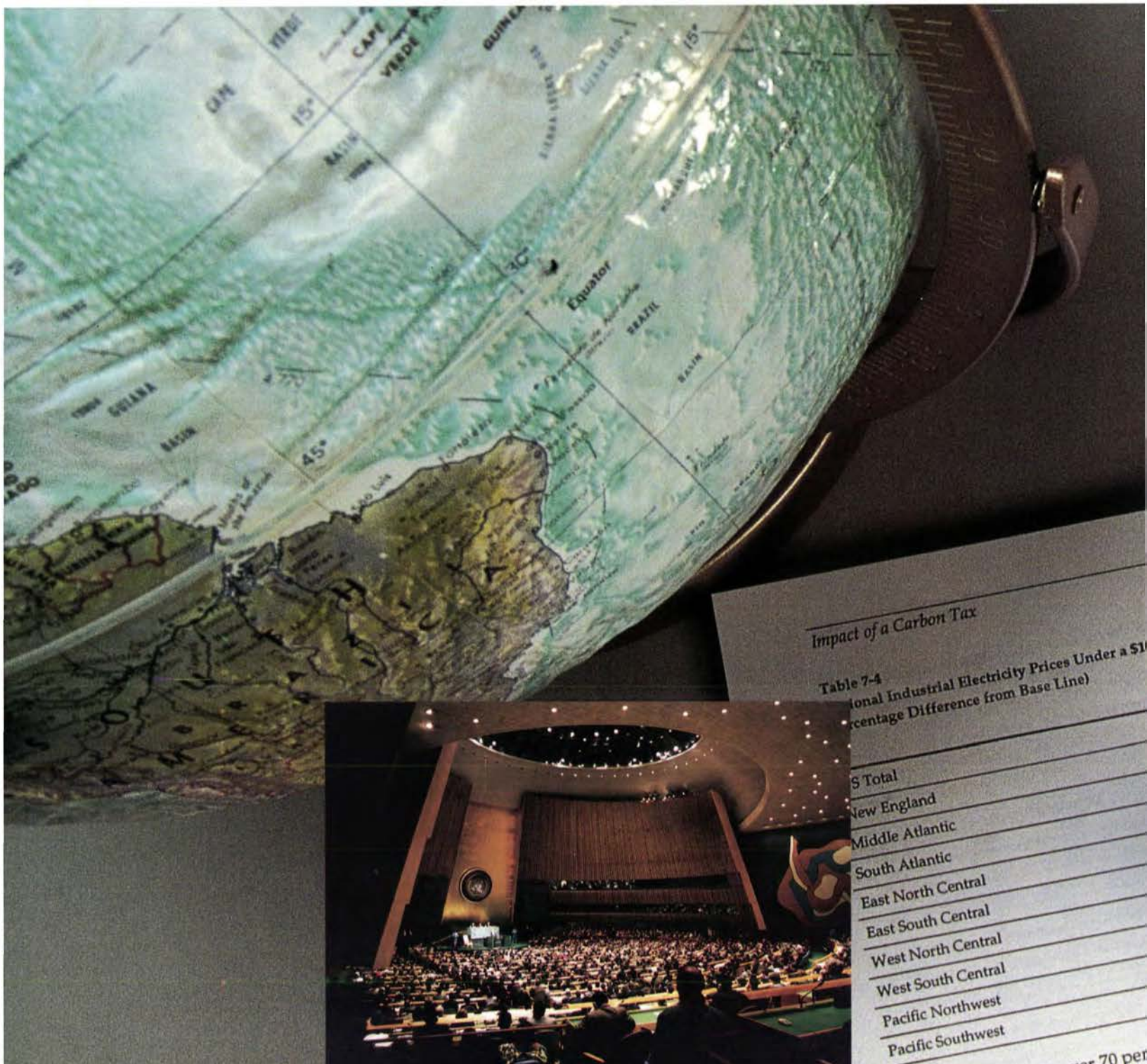
Understanding the Mechanisms of Forest Dieback

One of the most puzzling and potentially disturbing types of environmental degradation is dieback in temperate forests, which shows up as large dead areas in the roots, branches, or crowns of trees. Often fatal, dieback typically involves injury to a tree's water transport system, but little has been known about the underlying causes. Initially, acid rain was the suspected culprit, but recent concern has focused on other possible causes, including variation in climate.

New results from a study funded by EPRI, the U.S. Environmental Protection Agency, and Forestry Canada have shed important light on the mechanisms of dieback. An analysis of forest and climate data from 1910 to 1990 has produced two major findings: first, dieback is highly episodic and tends to be associated with an extended winter thaw that is followed by a sharp freeze; second, the most significant precondition for extensive damage in a forest is that the forest be fully mature. Acid rain does not appear to be a major factor.

Researchers have determined that during dieback episodes, forests can release major amounts of carbon dioxide to the atmosphere. Currently, the temperate forests of North America are thought to act as a net sink for atmospheric carbon, but extensive dieback resulting from climate change—or from other causes, such as mismanagement—might shift their status to that of a net source. To minimize dieback and carbon release, the researchers suggest maintaining forests in mixed-age stands rather than letting them reach full maturity.

■ *For more information, contact Lou Pitelka, (415) 855-2969.*



Impact of a Carbon Tax

Table 7-4
ional Industrial Electricity Prices Under a $1
rcentage Difference from Base Line)

S Total
New England
Middle Atlantic
South Atlantic
East North Central
East South Central
West North Central
West South Central
Pacific Northwest
Pacific Southwest

Table 7-5 shows that over 70 per
Central regions and the South A
electricity-intensive industries
deteriorating. The carbon tax h
Atlantic, and the two Pacific r
greater share of electricity ge
advantage because electricity

United Nations General Assembly

by John Douglas

GLOBAL CLIMATE RESEARCH

Informing the Decision Process

Impact of a Carbon Tax

Table 7-5
Regional Electricity Generation by Fuel Type
(Percentage of Total Generation, 1992)

	Coal	Oil & Natural Gas	Nuclear	Hydropower	Other
New England	19.2	30.4	44.9	5.1	0.5
Middle Atlantic	41.8	14.4	34.4	9.3	0.0
South Atlantic	59.0	10.4	28.1	2.4	0.0
East North Central	73.9	1.0	24.4	0.7	0.1
East South Central	72.7			8.3	0.0
				5.4	0.2
				2.1	0
				52.5	
				14.3	

Carbon Tax

2000	2010
37.2	34.2
20.2	26.4
28.4	30.3
43.9	41.3
50.3	48.5
38.5	35.3
56.8	

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THE STORY IN BRIEF

Public awareness of the potential for global climate change resulting from human activities has grown substantially in recent years. Policy actions aimed at greenhouse gas emissions include international accords such as the U.N. Framework Convention on Climate Change, national goals such as those set out in the U.S. Climate Change Action Plan, and state-level consideration of carbon dioxide emissions in integrated resource planning. Over half of human greenhouse gas emissions are believed to be CO_2. Thus the energy sector plays an important role in strategies to address the potential for climate change. Policy actions taken to mitigate the potential for climate change could affect electric utilities in many ways, as could actual changes in climate. EPRI conducts a wide-ranging research program that includes estimating the macroeconomic costs of compliance with emissions reduction proposals, determining the potential impacts of climate change, and developing integrated assessments to explore the advantages of various policy alternatives. In addition, EPRI has initiated a comprehensive effort to provide individual member utilities with the analytical tools they need to develop their own strategies for meeting emissions reduction goals.

Although major scientific uncertainties remain concerning the potential effects on global climate of increasing atmospheric concentrations of so-called greenhouse gases, policymakers at the international level have become proactive with regard to controlling emissions of these gases. The watershed event in this shift was the Earth Summit, held in Rio de Janeiro in 1992, which produced the United Nations Framework Convention on Climate Change. The stated goal of this convention is the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Although the issue of what constitutes dangerous interference is likely to remain the subject of intense debate for some time, the Framework Convention asks developed countries—as a first step toward stabilizing atmospheric concentrations—to aim to return their emissions to 1990 levels by the year 2000. More recently, with the adoption of the Berlin Mandate in April 1995, the policy focus has shifted to establishing post-2000 emissions targets.

These international agreements have potentially significant implications for the U.S. electric power industry. Because power generation represents a major source of carbon dioxide, electric utilities have become a focus for the emissions reduction and reporting activities of the Energy Policy Act of 1992, the Clinton administration's Climate Change Action Plan, the U.S. Department of Energy's Climate Challenge program, and other efforts. Such attention to carbon emissions could eventually have a significant effect on utility decisions, ranging from the choice of fuels for future power plants to the consideration of emissions offset options.

An important feature of the Framework Convention is its call for periodic policy reviews in light of the best available information on the science and economics of climate change, including the costs and benefits of emissions reduction. This information is currently being gathered by three working groups of the United Nations Intergovernmental Panel on Climate Change (IPCC), whose reports will provide critical input to the next round of international negotiations on greenhouse gas reductions. Ongoing EPRI research will provide input in all three areas covered by these state-of-the-art reports: climate science, impacts of climate change, and economics. Richard Richels, Technical Executive and target leader for global climate change research at EPRI, is a principal lead author of the IPCC's economic report.

"Through our research, we hope to help inform the policy process," says Richels. "Climate policymaking is a very long term process with many opportunities for learning and midcourse correction. EPRI research will provide critical information to the decision makers involved. The goal is to assist them in identifying policies that balance costs and benefits while achieving an effective outcome for global protection. The EPRI program to inform the policy debate has three components: first, to develop information on the costs of climate change management proposals; second, to develop information on what such proposals might buy in terms of reducing any undesirable consequences of climate change; and third, to provide a framework for weighing costs and benefits to help policymakers arrive at a balanced judgment."

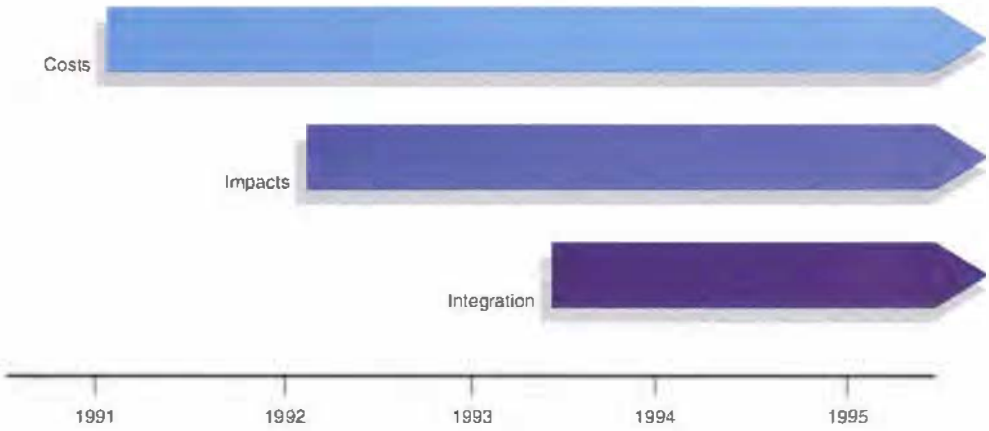
Costs of compliance

An early goal of EPRI's climate-related research was to develop a way to measure the macroeconomic costs of various proposals for reducing greenhouse gas emissions. This goal was accomplished in 1992 with the development of the Global 2100 model. The model, the product of a collaboration between Alan Manne of Stanford University and Richels of EPRI, is currently being used by researchers at more than 35 institutions worldwide.

A recent and particularly significant application of Global 2100 was motivated by the Berlin Mandate, which was adopted at the first meeting of the Conference of the Parties (COP-1) of the U.N. Framework Convention. The Berlin Mandate requires developed countries to set "quantified limitation and reduction objectives" for the post-2000 time frame. A proposal explicitly mentioned for study at COP-1 is the one put forward by the Alliance of Small Island States (AOSIS), which calls for developed countries to further reduce emissions—by an additional 20%—by 2005.

RESEARCH PROGRAM EVOLUTION

From an early emphasis on the cost of greenhouse gas management proposals, EPRI's global climate change research program has expanded to include consideration of what such proposals might buy in reducing environmental impacts. The program also now encompasses integrated assessments that synthesize information on the costs and benefits of various proposals.



As part of the analysis stage leading up to the consideration of alternative targets and timetables, EPRI recently conducted an analysis of the costs of implementing the AOSIS proposal. Three alternatives were considered. First, a case was evaluated that closely follows the original AOSIS proposal. Here each OECD (Organization for Economic Cooperation and Development) country acts unilaterally to reduce its own emissions by the additional 20% by 2005. The two other cases allow more flexibility in meeting the overall emissions objectives of the AOSIS proposal.

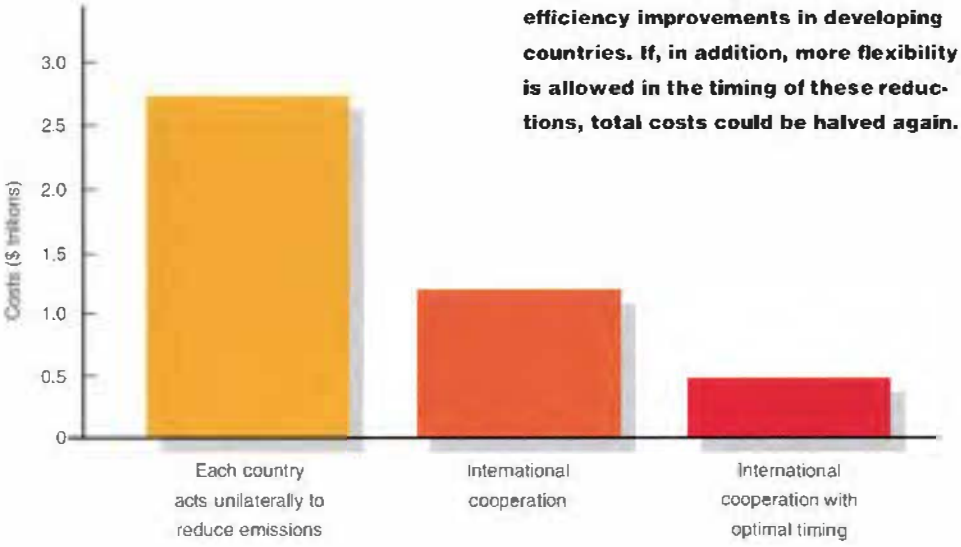
In case 2, emissions are reduced by the specified amount, but the reductions may be made where it is cheapest to do so. For example, if emissions can be reduced cost-effectively through energy efficiency programs in developing countries, then these are included in the portfolio of emissions reduction measures. In other words, the focus is on identifying the least-cost global solution for meeting each year's emissions targets.

Case 3 goes one step further in terms of achieving economic efficiency. The problem with tight near-term targets is that they require premature retirement of energy-producing and energy-using capital stock (e.g., power plants, houses, autos)—an approach that is likely to be extremely costly. The real issue, however, is not so much year-by-year emissions as it is cumulative emissions. Because of the long lifetime of carbon dioxide in the atmosphere, CO_2 concentrations (a major focus of the U.N. Framework Convention) are determined by the total amount of CO_2 released over an extended period. Accordingly, case 3 sets a limit on cumulative OECD emissions between now and 2050. The limit is equivalent to the sum of the year-by-year AOSIS emissions targets but allows flexibility as to how the limit is met.

For example, an OECD country may choose to emit more in the early years and less later on. The advantage of such a strategy is that it provides more time for an economical turnover of the existing capital stock. It also provides more time to develop low-cost alternatives to carbon-intensive fuels.

The results of this analysis show that costs are substantial in all instances but that case 1 is by far the most expensive. Allowing emissions to be reduced where it is cheapest to do so (case 2) cuts costs by more than one-half. And reducing emissions both where and when it is cheapest (case 3) allows costs to be halved again.

This analysis highlights the importance of economic efficiency considerations in the design of policies for meeting specific concentration targets. Article 3 of the Framework Convention states that "policies and measures to deal with climate should be cost-effective so as to ensure global benefits at the lowest possible costs." The EPRI study shows how economic analyses can be used to identify emissions reduction strategies that minimize the expense of achieving the desired concentration target.



COST OF COMPLIANCE One explicit proposal for reducing greenhouse gases is to have each developed country cut its emissions to 20% below 1990 levels by the year 2005. The same reduction goal could be met for less than half the cost by adopting an international cooperation approach, in which reductions are made where it is most cost-effective to do so—for example, by supporting energy efficiency improvements in developing countries. If, in addition, more flexibility is allowed in the timing of these reductions, total costs could be halved again.

Models such as Global 2100 focus on the global picture and present results in highly aggregated terms, such as the percentage of gross domestic product (GDP) various countries would forgo because of compliance with emissions reduction policies. In addition, however, U.S. policymakers are interested in the implications of their actions at the state and regional levels, as well as the implications for various sectors of the economy.

As a result, EPRI researchers are beginning to take a closer look at what underlies the aggregate numbers. For example, one frequently discussed option is to place a so-called carbon tax on the use of fossil fuels—a tax based on the amount of CO_2 emissions from each fuel. It has been estimated that a tax of $100–$200 per metric ton of carbon would be needed to stabilize U.S. emissions. An EPRI report on the economic impact of such taxes was published in November 1994.

Assuming a carbon tax of $100 per metric ton, the study found that real GDP in the United States would fall about 2.3% below baseline projections by 2010. About half of the calculated GDP loss would result from reduced consumption, while lower business investment would account for about one-third of the loss. Energy-related industries would be hardest hit: by the year 2000, the average price of coal would be expected to rise by 174% and that of natural gas by 36%. The effect of rising fuel prices on electricity rates would vary more than threefold between different regions of the country. By the year 2010, for example, industrial electricity rates would rise by 17% in the Southwest but by nearly 55% in the upper Midwest. Reduced capital spending by electric utilities would represent the largest single share of the total decline in business investment.

The reduction in capital spending by electric utilities explains an unexpected major finding of this tax research. Total natural gas consumption undergoes disproportionately large reductions through 2000. This is surprising, given that natural gas contains less carbon than coal does and that its price rises much less than coal's. The reason for this unusual situation is that a $100 carbon tax causes a 50% decline in electricity growth, due to demand damping. This in turn leads to cancellation of capacity additions, and through 2000 most capacity additions are expected to be natural gas fired.

For all industries, the average national cost increase associated with a $100 carbon tax would be 3.3%, but several nonenergy industries would be much more severely affected. The cost of making cement, for example, could be expected to rise by about 17%; aluminum, by 11%; and ferrous metals, by 8%. Meanwhile, the decline in real personal income would range from about 1.4% in the New England states to 2.9% in the upper Midwest.

The study concluded that "policies to reduce carbon dioxide will have pervasive impacts on the economy of the United States, because for the next decade or two, emissions can be held at or below current levels only by eliminating most of the growth in energy use that would otherwise occur."

Economic impacts of climate change

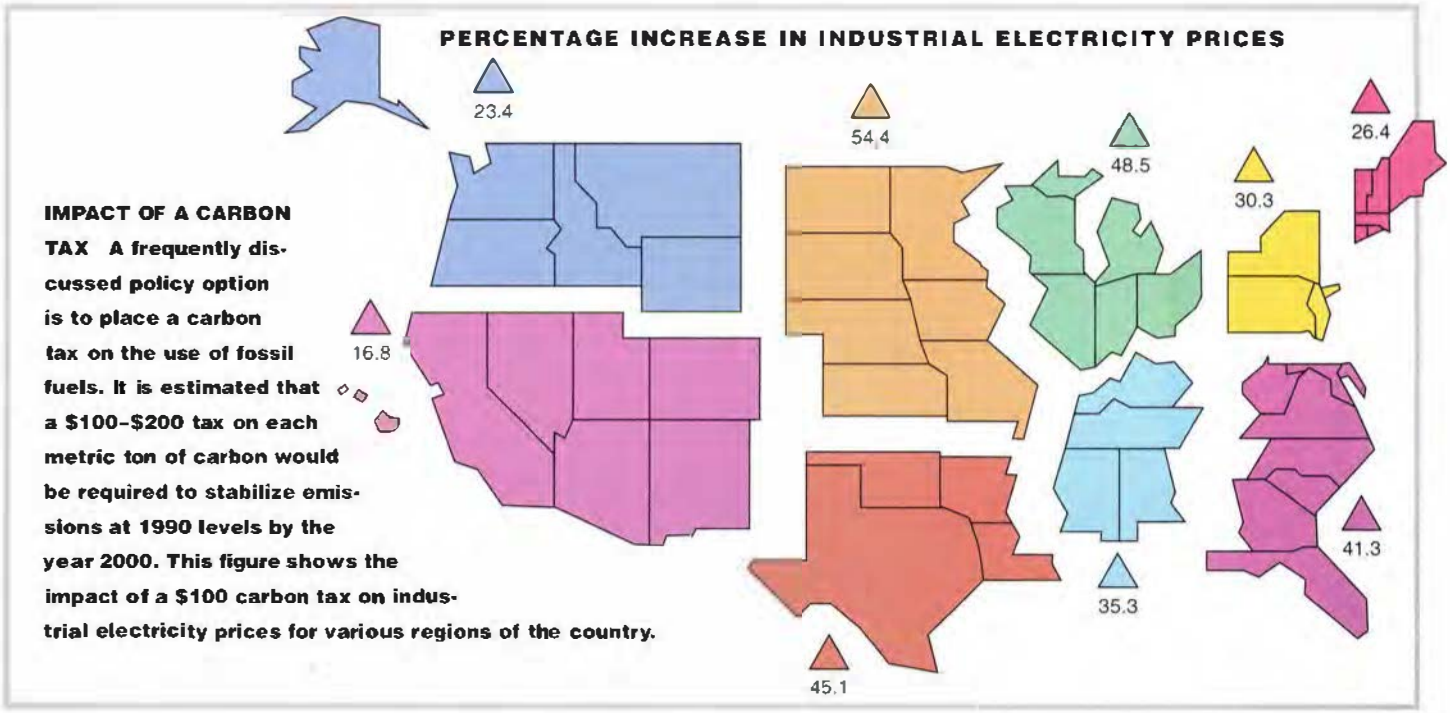
Costs represent only one side of the cost-benefit equation. Policymakers also need to know what mitigation measures will buy in terms of reducing any undesirable impacts of global climate change. Determining the potential benefits of mitigation is difficult. There is enormous uncertainty, for example, about how rising concentrations of greenhouse gases will affect key climate variables. And there is also uncertainty about how changes in key climate variables will affect the things that are important to us.

Climate modeling uncertainties

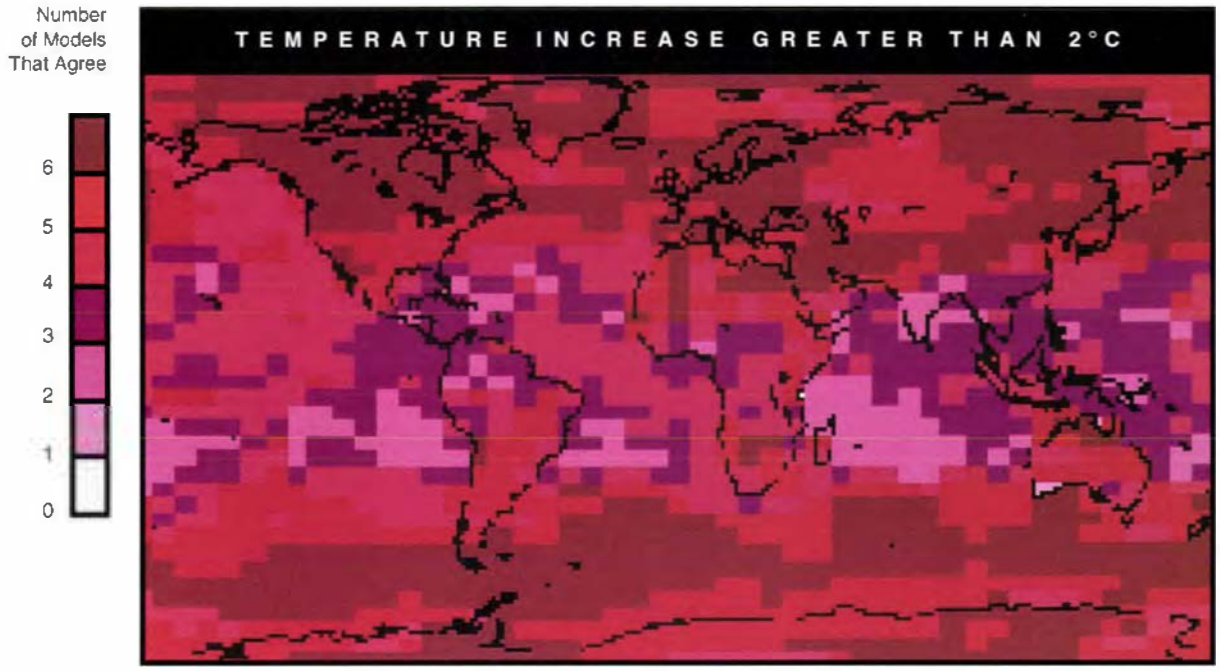
A nagging problem for policymakers as they consider the potential costs and impacts of climate change is that the predictions of change made by various models often do not agree. The Model Evaluation Consortium for Climate Assessment was formed in 1991 to quantify uncertainties in climate forecasts and to identify future research that could help reduce these uncertainties. The consortium is cosponsored by EPRI and eight other organizations—representing government, industry, and academia from several countries.

One major result to emerge from this work is a comparison of temperature and precipitation changes calculated by several climate models (technically, general circulation models, or GCMs) in response to an assumed doubling of greenhouse gases in the atmosphere. The results are displayed in a series of so-called agreement maps, available in hard copy in the *Climate Change Atlas: Greenhouse Simulations From the Model Evaluation Consortium for Climate Assessment* and viewable on-line on the EPRI World-Wide Web server. On the basis of previous simulations, the IPCC in its 1990 assessment reported a very wide probable range of projected equilibrium temperature increase for a doubling of atmospheric CO_2 concentrations: 1.5–4.5°C. In general, the GCMs evaluated by the consortium agree that a warming trend of more than 2°C is likely near the poles, but they show less agreement for regions in the middle latitudes. Even less agreement is seen in the predictions for changes in precipitation.

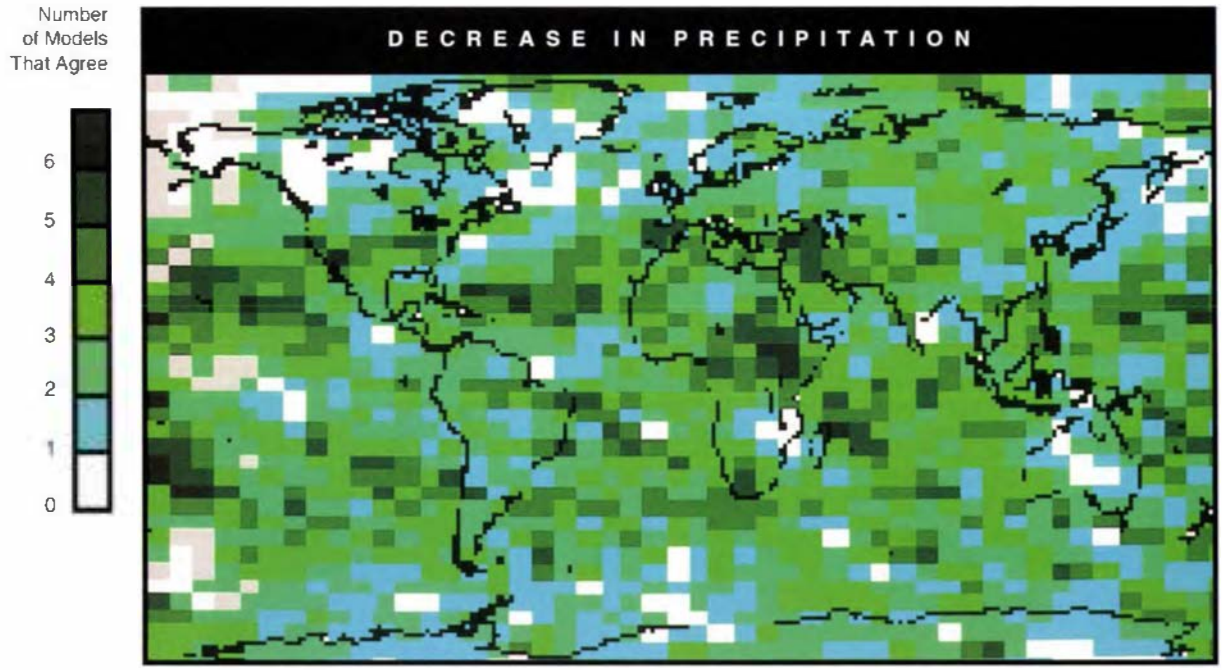
The consortium has also studied the importance of considering sulfate aerosols in the atmosphere, which had previously been ignored by most climate modelers. These aerosols, injected into the atmosphere by



IMPACT OF A CARBON TAX **A frequently discussed policy option is to place a carbon tax on the use of fossil fuels. It is estimated that a $100–$200 tax on each metric ton of carbon would be required to stabilize emissions at 1990 levels by the year 2000. This figure shows the impact of a $100 carbon tax on industrial electricity prices for various regions of the country.**



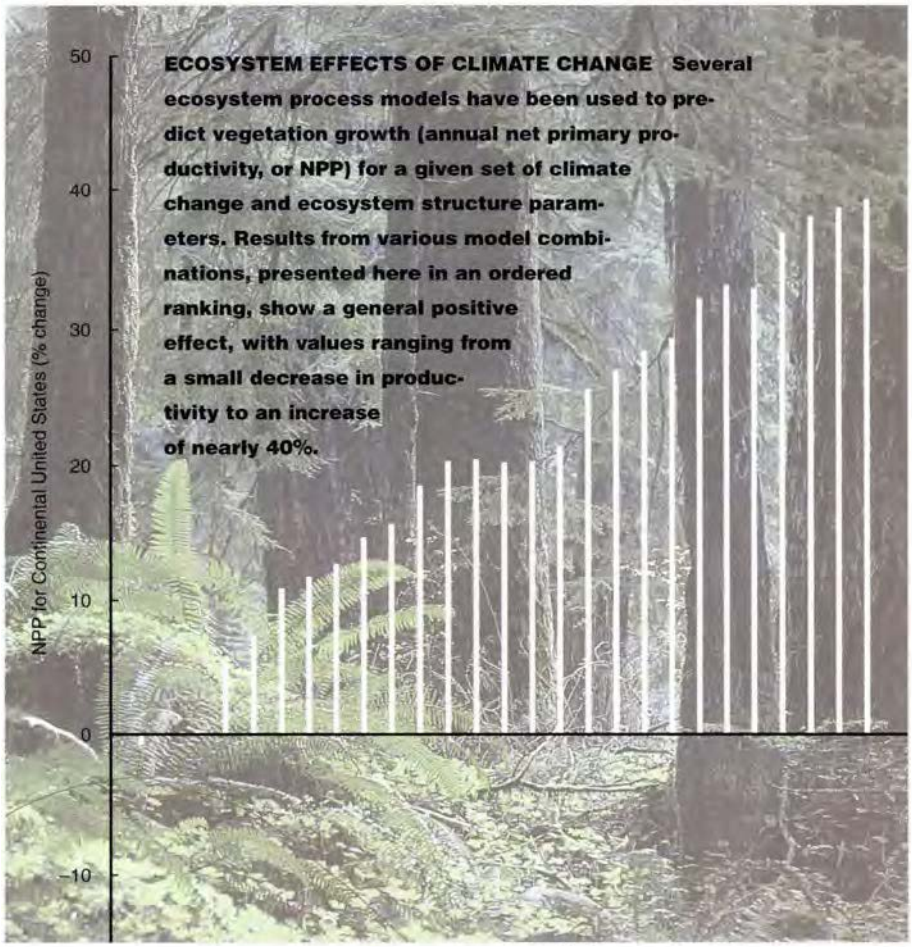
AGREEMENT ON CLIMATE CHANGE IMPACTS **Predictions about the effects of a buildup of greenhouse gases differ greatly among available climate models. These maps indicate how well different models agree on projections of changes in temperature and precipitation. In the top map, the shading shows considerable agreement among models that a doubling of atmospheric CO_2 concentrations would cause at least a 2°C increase in temperature toward the poles, but there is less agreement for the midlatitude regions. The same models show little agreement about whether precipitation will decrease with CO_2 doubling.**



volcanoes and by various human activities, including fossil fuel combustion, tend on average to cool the earth by reflecting sunlight. Globally, they now appear to have offset 30–40% of the expected warming trend from greenhouse gas emissions over the past two centuries. The role of sulfate aerosols in future climates is now being modeled by a number of investigators worldwide.

The consortium-sponsored sulfate modeling research by Karl Taylor and Joyce Penner of Lawrence Livermore National Laboratory was published in the June 30, 1994, issue of *Nature*. It set off a flurry of new modeling experiments on the climate change issue. In a *Nature* commentary on the research, Tom Wigley (a noted scientist involved in the IPCC assessments) stated, "The detection of anthropogenic changes in climate through modeling is not unlike looking for a needle in a haystack. These new results suggest that we may have been looking in the wrong haystack."

Compounding the problem of using the predictions of climate models as input for impact assessment studies is a fundamental mismatch in data requirements. Current climate models have relatively low spatial resolution—a single grid square typically covers more than 100,000 square kilometers—and temporal output is unreliable for periods shorter than a month. Impact models, on the other hand, often require input data with a spatial resolution of 100 square kilometers or less and temporal scales of one day or less. Experiments to develop ways of downscaling—for example, by embedding a fine-resolution grid in a key region of a conventional model—have provided only limited improvement, since errors originating at the boundary with the coarse grid tend to be compounded within the region of the fine grid.



ECOSYSTEM EFFECTS OF CLIMATE CHANGE Several ecosystem process models have been used to predict vegetation growth (annual net primary productivity, or NPP) for a given set of climate change and ecosystem structure parameters. Results from various model combinations, presented here in an ordered ranking, show a general positive effect, with values ranging from a small decrease in productivity to an increase of nearly 40%.

"Regional analysis remains the Achilles' heel of climate modeling," says Chuck Hakkarinen, EPRI project manager for the consortium. "Yet it is on the regional level that the specific effects occur that affect most people's lives. What we're finding is that trying to derive regional climate change from global models is very difficult at best and may not even be possible. Perhaps coupled climate models of global dimension but with regional scales will be needed—a requirement still beyond today's supercomputer capabilities."

Impacts modeling uncertainties

Some of the earliest research on climate change impacts was conducted by Yale economist William Nordhaus, who concluded that only about 3% of U.S. economic activity involves sectors—such as agriculture, forestry, and fisheries—that could be severely affected by climate change. Another 10% involves sectors—including energy industries, construction, and real estate—that could be moderately sensitive. The remaining 87% of the economy would be negligibly affected by climate change. In his pioneering work on this topic, Nordhaus concluded that the probable impact on the U.S. economy resulting from a doubling of CO_2 emissions would be a loss of only about a quarter of 1% of the GDP. However, he has pointed out that current studies omit some potentially important effects and that additional work is necessary.

Recent EPRI research has examined the potential impacts of climate change more closely, explicitly taking into account the potential for market-based adaptation, which was not considered by many early studies. Specifically, EPRI's climate change impacts program is designed to measure the impacts—both positive and negative—that would result from changing or delaying particular climate change scenarios. Early work in this program has focused on two of the areas identified by previous researchers as being most likely to receive significant impacts: coastal properties and agriculture.

One EPRI study, for example, has examined the economic impacts of a climate-induced change in sea level. The study notes that projections of the rise in sea lev-

el by the year 2100 have themselves been sharply reduced in recent years—from a high estimate of 3.5 meters, made a decade ago, to a current estimate of 64 centimeters—and projections appear to be declining further. Previous studies, based on a projected sea-level rise of 1.0 meter and assuming that all coastal areas would be protected immediately without regard to cost, generally concluded that the annual cost (in 1990 dollars) would be $7 billion to $9 billion by 2065. Updating these estimates to reflect current thinking about the magnitude of sea-level rise and to allow for market-based decisions about protecting coastal property lowers projected costs substantially. A central case estimate, for example, shows losses attributable directly to protecting or abandoning coastal structures to be about $150 million, a full order of magnitude less than the earlier estimates for structures.

Another EPRI study focused on agricultural impacts, using a well-established computer model that divides the United States into 10 farm product regions. A major goal of this study was to be more comprehensive than previous analyses, which tended to concentrate on grain crops and to allow only limited possibilities for adaptations at the farm level—a practice that some critics have derisively called the dumb-farmer hypothesis. In particular, the EPRI study allowed a shift toward high-value, heat-tolerant crops, such as fruits and vegetables, which might be planted more widely in southern regions if a warmer climate shifted grains to more northerly latitudes. The study also considered possible changes in forage and livestock production and potential changes in technology, such as breeding for increased heat tolerance.

By modeling 1990 agricultural conditions for a scenario in which the climate was assumed to change through a 2.5°C increase in temperature and a 7% increase in precipitation, the study found that the value of U.S. agricultural production would actually *increase* by nearly $15 billion a year; in comparison, a loss of $7.5 billion would be projected assuming no crop migration or farm-level adaptation. The final report of the study points out that, regardless of adaptation, these numbers represent less than 3% of the total value of America's agricultural products. It concludes, "In aggregate, climate change appears to be a relatively small stress to agriculture."

Nonmarket impacts

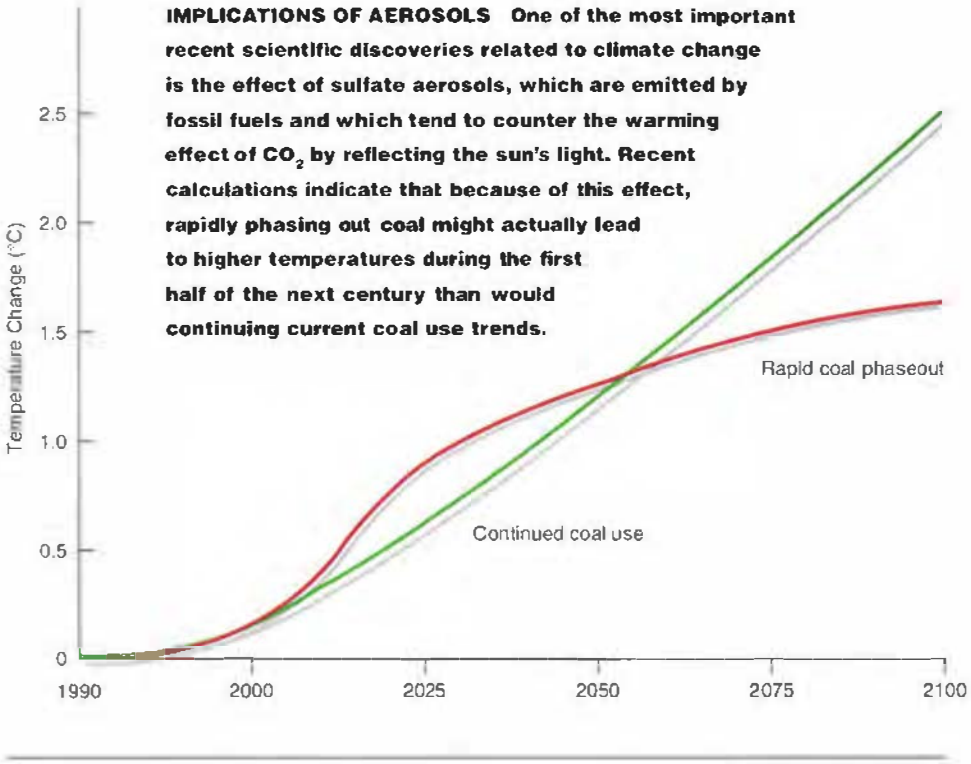
Agriculture is a good example of a market impact—that is, an impact that would show up in national income accounting. Market impacts generally include the items economists find easiest to count. Many valuable goods and services, however, are not included in national income accounts and have been omitted from most assessments of the impacts of global warming. Examples of important nonmarket impacts include effects on biodiversity, environmental quality, and human health. Research on the nonmarket impacts of climate change has not progressed nearly as far as research on market effects, which can be measured in terms of direct costs. The dual challenge for research on nonmarket impacts will be to determine the likely extent of such impacts and to find out how people value them. This effort will require the use of experiments and simulation models to identify important impacts and the development of innovative methods for impact valuation.

One assessment of the potential ecological effects of climate change on the United States was conducted by the Vegetation/Ecosystem Modeling and Analysis Project (VEMAP), sponsored by EPRI, the National Aeronautics and Space Administration, and the U.S. Forest Service. Since climate change can affect both ecosystem structure (the types of plants that grow) and ecosystem function (including overall productivity and carbon storage), VEMAP used three models for each type of response and compared their results for the continental United States under a range of future climate scenarios.

Using climate change patterns predicted by three leading GCMs for a future atmosphere with doubled CO_2, the three ecosystem structure models projected varying degrees of change in vegetation distribution, depending on which combination of models was used. In general, there was a northward movement of major vegetation zones, particularly in the eastern United States.

For projecting possible changes in processes important to the ecological and economic value of ecosystems, output from

IMPLICATIONS OF AEROSOLS **One of the most important recent scientific discoveries related to climate change is the effect of sulfate aerosols, which are emitted by fossil fuels and which tend to counter the warming effect of CO_2 by reflecting the sun's light. Recent calculations indicate that because of this effect, rapidly phasing out coal might actually lead to higher temperatures during the first half of the next century than would continuing current coal use trends.**



both the GCMs and the ecosystem structure models (i.e., new vegetation distributions) was used as input for the ecosystem process models. The simulated changes in annual net primary productivity (NPP) of vegetation covered a wide range but were generally positive, with increases of up to 40%. NPP is a measure of the amount of plant growth and so is a useful indicator of changes in the productivity of forests or rangeland.

Results were more ambiguous on the equally important issue of how total carbon storage in U.S. ecosystems could respond to climate change. The VEMAP models produced a very wide range of results—from a 39% loss of carbon to a gain of more than 30%. In other words, depending on the models chosen, terrestrial ecosystems were projected to either counteract or reinforce the buildup of atmospheric CO_2 and the associated climate change. This broad range reflects the uncertainty inherent in all three types of models used in VEMAP. Improvements in the models can be expected over time, however; the exercise of comparing the models and their outputs has helped to identify how the models differ and what new monitoring or experimental data are needed to resolve the major uncertainties.

EPRI's part of the VEMAP research was conducted at the Marine Biological Laboratory, Woods Hole, Massachusetts, and at the University of Lund, Sweden. Additional research, sponsored by the VEMAP cofunders, was conducted at other research institutions.

"Two key conclusions have emerged from our VEMAP work," says project manager Louis Pitelka. "On the one hand, it is clear that both vegetation distribution and ecosystem function are sensitive to climate change. On the other hand, there remains considerable uncertainty about *how* ecosystem properties are affected by climate change—and this uncertainty is further compounded by disagreement among climate models themselves as to how climate might change."

In order to help resolve some of the uncertainties related to forest productivity and carbon sequestration, EPRI has sponsored fundamental research on the response of forests to elevated CO_2 levels. According to initial results, both growth and carbon storage are stimulated by an increase in atmospheric CO_2, but the degree of stimulation depends also on the fertility of the soil, and maximum stimulation occurs only if sufficient nitrogen is available. Also, questions remain about whether the increased carbon sequestration is sustained over long periods.

It is even more difficult to determine the effects of climate change on animals than on plants, since these effects can depend on complex interactions with other animals and with particular types of plants. Initial results from the study of a few animal species indicate that they may be more affected by changes in vegetation—whether caused by global warming or human activities—than by climate change as such. But much more work needs to be done on the nature and magnitude of the impacts.

An EPRI program to determine public attitudes toward nonmarket impacts is just getting under way and will focus on measuring the importance people place on specific issues, such as shifting ecosystem boundaries, changes in ecosystem productivity, changes in the character and composition of ecosystems, and irreversible loss of species. As part of this program, researchers will have to consider how best to describe the ecological effects of climate change to the public, what methods can be used to rank these concerns with other social issues, and what quantitative measures can be used to present the results for use in discussions of policy options.

"We are just beginning pilot-scale experiments to study public perceptions and to develop a conceptual underpinning for full-scale research in this area," says Tom Wilson, manager of EPRI's climate change impacts research. "Combined with what we learn about nonmarket impacts, this information will provide critical insights for the overall decision-making process."

Integrated assessment

In order for decision makers to use the information generated in diverse areas of climate change research, further analyses will have to be made that reveal the implications of particular scientific results for policy and that explore the advantages of various policy alternatives. Such analyses are known as integrated assessments, and they represent a major new thrust in EPRI's efforts to inform the policymaking process.

OPTIONS FOR GREENHOUSE GAS REDUCTION **As individual utilities consider how they can reduce their own greenhouse gas emissions in the most cost-effective manner, they can choose among the variety of options listed here. EPRI has recently published a workbook that can help a utility analyze these options and rank them according to cost in light of its specific situation.**

- **Coal mine methane recovery**
- **Cogeneration**
- **Dispatch by environmental criteria**
- **Electrotechnologies**
- **End-use energy efficiency**
- **Fly ash reuse**
- **Forestation projects**
- **Fuel switching**
- **Generation efficiency improvements**
- **Landfill gas recovery**
- **New capacity choices**
- **Repowering**
- **T&D efficiency improvements**

The goal of this work is to develop computer-based decision support systems that will synthesize information on the costs and benefits of climate change management proposals. To do this requires modeling the relationship between human activities and greenhouse gas emissions, the effects of these emissions on climate, and the impacts of climate change on environmental and economic systems.

Developing an integrated-assessment capability of the scope and complexity required for evaluating global climate change management proposals is a formidable task. Three contractors—Battelle Pacific Northwest Laboratories, Carnegie Mellon University, and the Massachusetts Institute of Technology—are currently involved in this effort and are testing alternative approaches to integrated assessment.

Once completed, the integrated-assessment frameworks will allow analysts to compare directly the costs and benefits of policy proposals. The frameworks will also facilitate assessment of the value of alternative R&D strategies. Initial prototypes will be available by the end of 1995, and refinements will be made through the rest of the decade as knowledge and methods evolve. Policy and R&D analyses will be conducted as new proposals emerge.

One recent integrated assessment, conducted by Battelle Pacific Northwest Laboratories, has shown that the inclusion of new information about sulfate aerosols can have important policy implications related to the phasing out of fossil fuels. In the past, it was believed that one way to slow global warming would be to phase out existing coal-fired power generation capacity as soon as possible. That policy, however, ignored the global cooling effects of aerosols. When a simulation was made of what would happen if all existing coal plants were replaced by a carbon-free alternative in the next 20–30 years, the results showed that temperatures would actually increase faster for the first half century than under a business-as-usual policy. Only in the second half century would the decrease in atmospheric CO_2 outweigh the radiation-reflecting effect of sulfate aerosols. This highlights the complexities that policymakers face when designing strategies for dealing with the possibility of climate change.

Near-term decisions for utilities

Even before scientific uncertainties are resolved and emissions policies are finally established, however, electric utilities are becoming involved in greenhouse gas reporting and reduction activities that have far-reaching implications for virtually every aspect of their operations. To understand their future emissions reduction alternatives, utilities must be able to analyze the greenhouse gas ramifications of on-system options, such as choice of fuels and type of generation additions, as well as other options for offsetting emissions, such as tree planting. Responding to member needs in this area, EPRI has initiated a comprehensive effort to help address near-term decisions related to greenhouse gas emissions. The goal is to provide member utilities with the tools they need to fulfill emissions reporting requirements and to develop their own strategies for meeting possible emissions reduction goals in the most cost-effective manner.

In late 1994, EPRI published the *Workbook for Screening Greenhouse Gas Reduction Options*, which has already become widely popular in the industry. This workbook describes basic methods for screening options for emissions reduction or offset, and it presents costs and greenhouse gas reduction potentials for the various alternatives. Using spreadsheet templates that come with the workbook, utility staff can create a simplified "supply curve" of options—ranking them by marginal cost and showing the cumulative reductions that could be achieved by implementing a chosen set of options.

The current focus of work in this area is the development of a greenhouse gas accounting framework that will make it easier for utility staff to calculate and report both emissions and emissions reductions in a consistent manner. This software tool will enable an analyst to assemble data for a given utility system and for future emissions scenarios, choose from a variety of accounting and reporting options, and then produce reports in a standard format (such as Form EIA-1605, required by the Energy Policy Act). General distribution of the accounting framework is expected in 1996.

In addition to developing near-term planning tools, EPRI has sponsored studies of the possible long-term impacts on utilities of climate change and emissions reduction requirements. An initial study explored the potential direct impacts of physical changes in climate on utility operations. It calculated requirements for additional generation under alternative climate change scenarios, as well as the impacts on future electricity prices. Building on this earlier research, a recent study examined a range of climate and regulatory scenarios to determine their effects on six case study utilities—five in the United States and one in Japan. This work was cosponsored by CRIEPI (Central Research Institute of the Electric Power Industry), EPRI's Japanese counterpart.

Although results varied considerably among the scenarios chosen and among the utilities involved, one clear conclusion was that the costs associated with CO_2 reduction requirements would be much larger than those resulting from direct climate change impacts. The study concluded that policies to limit greenhouse gas emissions could radically alter the mix of generation technologies, and further research is now being undertaken to determine the potential impacts of such policies on specific utility resource planning decisions.

"EPRI's global climate change research has two major thrusts—to inform public policy and to help utilities manage climate-related risks—and I believe we have made considerable progress in both areas," says Stephen Peck, vice president for EPRI's Environment Group. "Perhaps most important, we have shown how policies and decisions can be made more cost-effectively. As a society, we are constrained in the amount we can spend to reduce environmental risks. It is essential that our risk reduction dollars are spent wisely. This goal is in keeping with both the U.N. Framework Convention and the needs of our member utilities." ■

Background information for this article was provided by Richard Richels, Tom Wilson, Chuck Hakkarinen, and Louis Pitelka of the Environmental & Health Sciences Business Unit.

by Leslie Lamarre

Renewables

Rancher Donald McIvor was somewhere in the middle of a C. S. Forester novel when he heard the coughing and sputtering of the gasoline-powered engine. If he hadn't been there to catch the problem, some 80 head of cattle in his west Texas herd of 400 could have suffered; the engine powered a pump for an underground well—the only source of water for the Herefords.

in a Competitive World

Sitting in the shade of an oak tree engrossed in sea stories from the Napoleonic Wars is not typical for ranchers in these parts. But the way McIvor sees it, he had no choice. Like the diesel- and propane-fired generators he tried at the same well, the gasoline engine required close attention. "You've got to fuel them up, turn them off, and check the oil at least once a day. If you're not there to shut them off once they pump the well dry, they can burn themselves out."

Water-pumping problems are a way of life for many ranchers in this parched corner of the Chihuahuan desert, where the sun shines relentlessly most days of the year. For more than a century, ranchers have relied on windmills to drive many of their water pumps. But this somewhat antiquated technology has several drawbacks, including high capital cost and extensive maintenance requirements. And as McIvor's experience shows, fossil fuel generators carry their own set of problems.

But now there's a new option—a cost-competitive system powered by photovoltaics (PV) that avoids the drawbacks of most other applicable water-pumping systems on the market. And West Texas Utilities Company intends to capitalize on this technology. WTU, an operating company of Central and South West Corporation, has entered into a joint venture with Solamotor of Texas, the company that developed the system. The patented commercial systems to be installed as part of the venture are identical to the one that took the place of the fossil fuel pumps that had given McIvor so much trouble. McIvor has been relying on the PV system for over a year now. "It's trouble free and a lot cheaper than a windmill," he says, adding that he

THE STORY IN BRIEF

Using the power of the sun to water cattle is just one example of the many niche applications in which renewable energy technologies are already cost-effective. Although increased competition in the electric utility industry has caused most companies to pare down or eliminate their budgets for renewable technologies, a number of utilities continue to pursue existing and emerging renewables markets. Some of these utilities view the niche applications as profitable business opportunities. Others are motivated by a desire to gain experience with renewable technologies or are even responding to a strong customer interest in renewables. But whether the utilities pursue business ventures, demonstrations, or R&D programs, one perspective they share is that renewables will be an integral part of the future power generation mix. And they want to be ready.

"Renewables are not being singled out. Utilities are cutting back on all long-term generation investments, and since renewables were poised as the next-generation technology, they are suffering greatly."

—Ralph Cavanagh, Natural Resources Defense Council

plans to install a solar booster pump to deliver water from the same well to an area 2 miles away.

In the next year, WTU will install 20 more of the solar-powered water-pumping systems in its 52,000-square-mile service territory. And this may be just the beginning. "We are the sole distributor for this technology," says Ward Marshall, manager of renewable resource development for Central and South West Services. "We hope to sell the systems throughout our 152,000-square-mile service territory, which includes parts of Texas, Oklahoma, Louisiana, and Arkansas."

Electric utilities that are investing in renewables or even funding renewables research are something of a rare breed these days. Indeed, the onslaught of competition in the industry has driven utilities into a cost-cutting rampage in which many are scaling back or cutting entirely their renewables budgets. "Renewables are not being singled out," stresses Ralph Cavanagh, energy program director for the Natural Resources Defense Council. "Utilities are cutting back on all long-term generation investments, and since renewables were poised as the next-generation technology, they are suffering greatly."

At the same time, however, a number of utilities like WTU are choosing to pursue renewables precisely because of the more competitive business environment. Marshall of Central and South West Services describes it as an economic decision. "As competition increases, it's even more important that we look for new and different ways to make money," he says. "The business venture with Solamotor is something that makes economic sense."

Watching closely the unfolding of events in Texas is Karl Rábago, a former public utility commissioner for the state and now the U.S. Department of Energy's deputy assistant secretary overseeing renewable technologies. "Sustainable energy systems, dominated by renewables, will be a major component of the world's energy supply sooner in the twenty-first century than most people realize," says Rábago. "As a result, utilities now have an unprecedented opportunity to build capability and experience to enter into a nearly unlimited international market for renewable energy systems, using unique domestic opportunities and niche markets as a launching pad."

While few utilities are pursuing renewables-oriented business agreements like WTU's, a number are continuing aggressive renewable energy programs and are even stepping up their renewables investments to prepare for what they anticipate will be a future that inevitably involves renewables as a critical part of the generation mix. Some of these utilities are motivated by a desire to gain experience with renewable technologies. Others are responding primarily to a strong customer interest in renewables. Still others want to be prepared for such possible crises as rapidly escalating fossil energy costs, carbon taxes to discourage fossil fuel use, and terrorist attacks on large, central-station power plants. But regardless of their motivation, these forward-looking utilities are certain they are on the right course.

Market opportunities

Teaming up with WTU to market the solar-powered water-pumping systems made

1

2

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NEVADA POWER **Nevada Power recently initiated an aggressive renewables program that includes the establishment of a solar test facility in Las Vegas. Among the technologies to be installed and monitored at the facility are a prototype 20-kW integrated high-concentration PV system by Amonix (1) and a prototype 20-kW dish-Stirling solar-thermal system by Science Applications International Corporation (2). The utility also owns an 18-kW flat-plate PV system at the University of Nevada in Las Vegas —the largest grid-connected PV system in southern Nevada (3).**

Pursuing the Renewables Market

Most of the cost-competitive opportunities in renewable energy technologies in the United States today exist in niche applications, particularly for photovoltaics. In addition to consumer products like solar calculators and wristwatches, PV modules are already cost-effectively powering roadside call boxes, corrosion protection equipment, remote monitoring systems, and a score of other devices. But the commercial PV market is showing signs that bigger things are just around the corner. One of the best indications to date was the announcement in December 1994 that Amoco and Enron were establishing a joint venture to manufacture PV modules for grid-connected applications and to develop solar-powered electric generating facilities around the world.

This Solarex building in Frederick, Maryland, now doubles as the headquarters for the joint venture Amoco/Enron Solar.

"Here are two large, well-respected energy companies making a business decision to pursue the PV market on a grand scale," says Allan Hoffman, the U.S. Department of Energy's associate deputy assistant secretary overseeing renewable technologies. "That's a big endorsement for photovoltaics." Indeed, Amoco and Enron officials have stated that they believe PV "will become a major source of energy for the world economy in the next century."

The joint venture, called Amoco/Enron Solar and effective as of January 1995, is headquartered in Frederick, Maryland. It runs the businesses previously operated by Solarex Corporation, the Amoco company that was the largest U.S. manufacturer and marketer of PV modules and systems. A separate division of the new company—Amoco/Enron Solar Power Development (AESPD), headquartered in Houston, Texas—is responsible for the development of worldwide power marketing and for projects that produce and sell solar electricity. As part of the joint venture, Amoco and Enron have agreed to fund a $25 million manufacturing facility for thin-film PV modules, which is expected to produce more than 10 MW of large-area, multijunction amorphous silicon modules a year.

Hoffman notes that the developing world should provide a significant market for the new joint venture. According to the World Bank, developing countries alone will require 5 million MW of new generation over the next 30 to 40 years. This compares with today's worldwide total installed capacity of just over 3 million MW. Amoco/Enron is already pursuing the developing world aggressively, with negotiations currently under way in India and Pakistan. (See *EPRI Journal*, July/August 1995, p. 26, for more information on opportunities in the developing world.)

The Amoco/Enron partnership came on the heels of an announcement by Enron that it would like to build a 100-MW PV-based power plant in the Solar Enterprise Zone, an economic development zone for solar projects that is expected to be located in southern Nevada. Further, Enron proposed to sell the electricity from this plant to the federal government for 5.5¢/kWh, with a 3% annual rate increase to allow for inflation. Industry observers were stunned by this proposal, since PV-based electricity currently sells for about 25¢/kWh. Nevertheless, says Robert Kelly, CEO of AESPD, "we're not going to lay the gauntlet down unless we can do what we say." The Corporation for Solar Technology and Renewable Resources, which is in charge of establishing the Solar Enterprise Zone, is considering this proposal. A decision is expected to be made in the first quarter of 1996.

Just like PV prices, the costs of large-scale wind projects are declining. Northern States Power Company recently received the industry's best price yet on wind power—a partially subsidized price of 3¢/kWh, levelized over 30 years—from Zond Systems. This cost is comparable to that of electricity from new fossil-fired power plants; however, since wind does not provide firm capacity, the value of wind energy is lower. (NSP officials note that the price does not include substation upgrading and the addition of a feeder system that will handle the extra capacity; nor does it include the cost of rights for the land, which NSP is providing.) The utility has accepted Zond's proposal, which will result in the deployment of 100 MW of wind turbines by the end of next year.

The pricing of biomass-based power is a bit more complex than that of solar or wind power, since biomass activities include both the cofiring of wood waste (in which case utilities are sometimes paid for taking the waste) and the use of energy crops, for which a supply infrastructure has not yet been established. Once such an infrastructure is established, however, a combination of waste wood and crop fuel is expected to be cheaper than coal in some utility systems. Energy crops can also be gasified for use in high-efficiency gas turbine systems. □

Working Together for Renewables

In an effort to encourage the development and commercialization of renewable technologies, EPRI and the U.S. Department of Energy often collaborate on projects they perceive as particularly valuable. Here are some examples of current projects.

Utility Wind Turbine Performance Verification Program

Created through a memorandum of understanding signed by EPRI and DOE in September 1992, this program aims to accelerate wind power commercialization and facilitate utility involvement. The program's long-term objective is to ensure the commercialization of field-verified, state-of-the-art utility-grade wind power systems capable of delivering electricity for under 4¢/kWh, given 13-mile-per-hour winds. Up to a dozen advanced turbines are being tested at each participating utility to obtain data on siting, permitting, construction, and performance. The turbine testing got under way late this year at Central and South West Corporation. Green Mountain Power Corporation is scheduled to host the next round of testing. The machines are being deployed and evaluated for three years, enough time to allow a thorough assessment of their performance and suitability for large-scale application.

Biomass Case Studies

Over the past two years, EPRI and DOE have cofunded case studies at various EPRI member utilities to analyze the feasibility of using biomass—both waste material and energy crops—in specific locations. The case studies, the last of which are drawing to a close, have involved Hawaii Electric Light, Maui Electric, Northern States Power, New York State Electric & Gas, Carolina Power & Light, and the Kansas Electric Utilities Research Program. The studies have explored a variety of site-specific fuels and energy conversion processes, as well as benefits beyond power production that could help make biomass use more cost-effective. For instance, a study at Northern States Power on the use of alfalfa crops as fuel indicated that the alfalfa leaves could be sold as high-nitrogen animal feed and the plant stems could be gasified. DOE recently issued a request for proposals for demonstration projects, providing the opportunity to turn these case studies into real projects. EPRI will help support member utilities that are involved in the selected projects. Late this summer, EPRI and DOE formalized their joint efforts in the biomass area through a memorandum of understanding.

Photovoltaics for Utility-Scale Applications

PVUSA is an eight-year-old cooperative research effort by a dozen electric utilities and federal and state government agencies. Led and managed by Pacific Gas and Electric and supported by DOE and EPRI, the effort is primarily based in Davis, California, at an 86-acre site dedicated to testing emerging and commercial PV systems. Currently, 18 PV arrays are undergoing testing—10 at the Davis site and the remainder at affiliated sites in various states. The applications include a 500-kW PV system with passive tracking that was installed on a feeder near PG&E's Kerman substation in the Fresno area and a 200-kW system with active tracking at the Sacramento Municipal Utility District's Hedge substation. SMUD will take over management of the PVUSA effort early in 1996.

Utility Photovoltaic Group

A group of electric utilities established UPVG in 1992 with support from EPRI, the American Public Power Association, the Edison Electric Institute, and the National Rural Electric Cooperative Association. Accelerating cost-effective PV applications, aggregating market demand, and demonstrating near-term uses are the goals of the organization, which is sustained by investments from its member utilities (now numbering 90), a grant from DOE, and technical support from EPRI. Among other projects, UPVG has published a six-volume analysis of PV status, opportunities, and markets and has developed a comprehensive action plan for stimulating demand in those markets. The centerpiece of UPVG's strategy for encouraging electric utilities to implement PV technologies is a program called TEAM-UP (Technology Experience to Accelerate Markets in Utility Photovoltaics)—a $500 million, six-year initiative to speed up the demonstration of 50 MW of on-grid and off-grid prototype, precommercial, and early commercial utility-related PV applications. TEAM-UP has been cited by the Clinton administration's Climate Change Action Plan as a model for other renewable technology commercialization initiatives.

Solar Two

Spearheaded by Southern California Edison and DOE and funded in part by EPRI, the Solar Two project will demonstrate a solar-thermal technology employing molten salt to store heat and generate steam. Touted as the most advanced solar central-receiver plant in the world, the 10-MW Solar Two facility will come on-line early in 1996 and will run through 1998, supplying power to SCE's grid. The $48.5 million project involves the conversion of the central-receiver plant constructed in the Solar One project. Located near Barstow, California, in SCE's service territory, Solar One operated from 1982 through 1988. It demonstrated the technical feasibility of the central-receiver concept but relied on a water-steam heat transfer system. Solar Two's molten salt system is expected to improve efficiency and operating performance because thermal energy collected during the day can be stored in the molten salt to produce electricity as needed—even after the sun goes down. Hence, in the event of cloud cover or an outage, the plant can tap this stored thermal energy to provide continuous electricity generation. □

"We got involved in biomass to reduce our carbon dioxide emissions. But we're finding that biomass offers competitive advantages that make it the number one renewable for TVA."

—Dale Bradshaw, Tennessee Valley Authority

sense for Solamotor. The company gains access to the marketplace through an entity the customers already know and trust. For its part, WTU gains the chance to meet a pressing customer need and make some money at it. Under their joint venture agreement, established in 1995, Solamotor focuses on the design and manufacture of the units, while WTU handles the sales, financing, warranties, installation, and service. The utility buys the units wholesale from Solamotor and sells them to customers, keeping any profit from the sales.

The solar-powered system is the first cost-effective, reliable pumping system for low-lying water, such as that in west Texas, and WTU officials expect it to do well in their service territory. Aside from saving the utility the cost of building new distribution lines, the venture is expected to help bring WTU closer to its customers at a time when such relationships are critical. Steven Leggett, the utility's business ventures consultant, draws an analogy with selling appliances, an activity WTU has been involved in since its beginning. "Electricity is kind of intangible," says Leggett. "People can talk all they want about getting to know your customers, but it's hard to do that if you're only making and selling electricity. On the other hand, when people come into your office and you show them different appliances and help them select the one that's best for their needs, you get a much closer feel for the customer."

Another utility pursuing renewables largely to gain an economic advantage is the Tennessee Valley Authority. Although TVA is in the research and development phase, it has high expectations for renewables—particularly biomass, which it expects will be an important part of the future generation mix. In preparation for cofiring biomass on a regular basis at pulverized-coal plants located close to ready sources of wood residues (e.g., sawmills, paper mills, and furniture manufacturers), TVA has conducted successful tests at two plants, burning up to 5% biomass. "We got involved in biomass to reduce our carbon dioxide emissions," says Dale Bradshaw, TVA's senior manager for energy options development. "But we're finding that biomass offers competitive advantages that make it the number one renewable for TVA: it lowers fuel costs, slightly reduces our sulfur emissions, does not impact boiler performance, and may reduce emissions of nitrogen oxides. At the same time we're providing a significant service to customers that have wood waste disposal problems. And TVA can use the wood waste more efficiently than customers could use it to generate their own electricity."

Over the past decade, TVA has been developing—with the help of funds from DOE—a proprietary biorefining process for use with wood waste and energy crops like switchgrass and fast-growing trees. This process will convert biomass into such marketable chemicals as ethanol, furfural, and lactic acid. A by-product of the process, lignin residue, could be fed to a gasifier to power a turbine and generate electricity cleanly. TVA expects the process to become commercial within five years if further funding is available. Bradshaw notes that

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TU ELECTRIC **TU Electric's 70-acre Energy Park in Dallas has provided the utility with the opportunity to gain hands-on experience with wind and solar energy technologies. Pictured here are a dish-Stirling solar-thermal system (1), a concentrating PV system (2), and two 300-kW wind turbines (3).**

"Technologies like PV systems and wind turbines are small enough in scale that you can kick the tires on 'em. You can't do this with other utility technologies. You simply can't afford to buy a new coal plant just to learn how to use it."

—Bill Muston, TU Electric

the success of this project could significantly aid rural economic development, putting tens of thousands of acres of idle farmland back into productive use and providing a good income for the region's farmers. And, he points out, "the more money that is pumped into the economy, the more industries will locate here. So we can get a lot of this investment back."

Getting the investment back is exactly what TU Electric hopes for. In 1993, the utility established its 70-acre Energy Park to showcase promising technologies based on wind and solar energy—two abundant resources in its west Texas service territory—and to gain hands-on experience with these technologies. For the park the utility selected a location near its main office in Dallas, an area convenient to the greatest number of employees and customers. "The Energy Park allows TU Electric to experiment with cuttingedge renewable technologies and evaluate their capabilities," says Bill Muston, the utility's manager of R&D. "Technologies like PV systems and wind turbines are small enough in scale that you can kick the tires on 'em. You can't do this with other utility technologies. You simply can't afford to buy a new coal plant just to learn how to use it."

Muston notes that the anticipation of increased competition in the industry has forced TU Electric to scale back plans for additional technologies in the park. However, the company is pursuing public utility commission approval for the purchase of 40 MW of wind power from a proposed wind farm in west Texas. "Our company is largely dependent on natural gas," says Muston. "There is some possibility that in the future gas will get expensive, and having some experience with wind power will help us determine how well it will fit into our future plans."

Experience pays

The desire to gain experience is a significant factor motivating many utilities to invest in renewable technologies. "These utilities know that they will ultimately have to depend—at least in part—on renewable energy technologies in the future," says Jim Birk, manager of EPRI's Renewables & Hydro Business Unit. "They want to be prepared with all the knowledge they can gather." And knowledge alone can make quite a difference. Birk offers the example of a utility's decision on whether to site wind turbines in a 10- or a 12-mile-per-hour zone. "Two miles per hour may not sound like much," he says. "But anyone who has had experience with wind projects knows that there's 72% more energy in the 12-mile-per-hour zone, since the energy in wind is proportional to the cube of the wind's speed."

One Canadian utility cares so much about gaining experience with renewables that over the next five years it plans to purchase 125 MW of renewable energy capacity it doesn't even need. "The point is not to give us more capacity. We've got plenty of that," says a representative of the utility, noting that it has about 33,000 MW of generating capacity, well above its peak demand of 23,000 MW. "The idea is to build experience in implementing, contracting for, and maintaining these new technologies."

Similarly intent on gaining experience with renewables—particularly in light of the industry's more competitive environment—is the New York Power Authority. In fact, virtually all of the utility's renew-

NORTHERN STATES POWER A 15-kW PV system on the roof of the Science Museum of Minnesota in St. Paul—the largest PV installation in the upper Midwest—has been supplying power to NSP's grid since November 1993. Also shown is a cluster of wind turbines from a 25-MW installation at Buffalo Ridge, Minnesota, where the utility will add another 400 MW of wind power capacity by the end of 2002.

"These utilities know that they will ultimately have to depend—at least in part—on renewable energy technologies in the future. They want to be prepared with all the knowledge they can gather."

—Jim Birk, EPRI

able energy efforts were initiated only recently. One of these, for which NYPA is awaiting approval, calls for the development of a 9-MW wind energy project on Plum Island. It would be the state's first commercial-scale wind project. Meanwhile, the utility is in the process of installing a 300-kW PV system atop a bus maintenance garage in the Bronx owned by the New York City Transit Authority. And it will soon be awarding a contract to a PV manufacturer to locate and build, in New York state, a manufacturing facility for PV systems. "Our plans are to install 1 MW of PV per year between 1997 and 2001," says Shalom Zelingher, the utility's director of R&D. "We're trying to get our feet wet and are interested in keeping our options open with respect to renewable technologies. We're very much interested in clean technologies that could generate electricity competitively in the twenty-first century."

Why not wait until renewable technologies become cost-competitive with conventional utility technologies? "Unless utilities have direct, hands-on experience, they won't be ready institutionally to incorporate these technologies into their systems," says Muston of TU Electric. Industry observers note that this is exactly what happened to a number of utilities when natural gas prices dropped quickly and combustion turbine technology improved dramatically. Many utilities who had foreseen the potential gas boom had planned to take advantage of it when it arrived. But, as one observer points out, "when it did come, it went right past them."

Customer push

With competition increasing, utilities are finding it more important to be responsive to customers' desires. And one of those desires, some have learned, is a greater renewables investment. That's what the Sacramento Municipal Utility District discovered through a 1993 customer survey.

SMUD's survey showed that 70% of the general population—and 88% of the group identified as the "green" population—were willing to participate in a special program that would result in the addition of renewables to the district's system at a slightly higher cost to the customers. Acting on the encouraging results of this survey, SMUD established its PV Pioneers program. Through this program, residential utility customers offer the use of their rooftops for PV panels that provide electricity to the utility grid. They also agree to pay 15% more on their monthly electric bills, which amounts to $4–$6 per month for the average homeowner. SMUD purchases, owns, installs, and maintains the systems.

The PV Pioneers are well aware that the electricity generated on their roofs does not directly supply their homes, says Stephanie McCorkle, public information specialist at SMUD. "They want to be part of the movement to further solar power, to be part of the clean air solution," she says. "They know that through such efforts to demonstrate the technology now, the price of PV will come down." Indeed, in the three years since the program was established, the prices of the rooftop units used have dropped some 25%.

By the end of 1995, the PV Pioneers program is expected to result in a total installation of 335 rooftop units, each typically ranging from 3.5 to 4 kW. "In an urban environment, space is at a premium," says Ed Smeloff, a member of SMUD's board of directors. "Having this extra capacity within the grid provides voltage support and defers the need for additions to the distribution infrastructure."

The PV Pioneers effort is just one facet of SMUD's Advanced and Renewable Technologies Program, which costs about $11 million a year, or 1% of the utility's annual revenues. "That's a modest amount in the scope of the whole budget," says Smeloff. "It's not an enormous investment if it's done on a sustained basis rather than waiting for a crisis and conducting a crash program. In a competitive market, I think you need to be able to provide your customers with what they want and demand."

Nevada Power Company found a similarly receptive response to PV in a 1993 survey. The survey showed that 58% of Las Vegas residents were willing to pay 15% more on their monthly electric bills for a solar power plant. An additional 26% said they would pay something less than 15% for such a plant, while 16% said they would pay nothing. "There's a lot of support in the state right now from both our customers and our politicians to help accelerate, to the extent reasonable, the introduction of solar energy technology in southern Nevada," says Mark Shank, the

TENNESSEE VALLEY AUTHORITY **This waste wood, in the form of sawdust, will be processed and then stored under the tent before being mixed with coal for a test firing at TVA's Allen fossil plant.**

"It's not an enormous investment if it's done on a sustained basis rather than waiting for a crisis and conducting a crash program. In a competitive market, I think you need to be able to provide your customers with what they want and demand."

—Ed Smeloff, Sacramento Municipal Utility District

utility's team leader for supply-side planning. A relatively new player in the renewables area, the utility last October received approval of a resource plan that includes an aggressive renewables program, with a heavy emphasis on PV-based R&D.

Customers aren't the only ones encouraging utilities to pursue renewables. Some states continue to mandate that their utilities invest in a specified amount of renewables generation. Such is the case for Northern States Power Company. NSP is no stranger to renewable technologies. The utility's service territory harbors some of the best wind resources in the country. In fact, NSP's own research in the mid-1980s led to the identification of Buffalo Ridge, Minnesota, as a hot spot for wind turbines. The utility has taken advantage of its ample wind resources since 1981, when it purchased its first wind turbine. Its first grid-connected PV system went on-line in 1982. NSP is also aggressive in the area of biomass, using more wood as generation fuel—mainly waste from sawmills—than any other electric utility in the country.

Still, the state wants to see more action. So when NSP asked for permission to store spent fuel at one of its nuclear plants, the legislature granted the request on the condition that the utility do more with renewables. The mandate requires NSP to install 425 MW of wind capacity by the end of 2002 (25 MW toward that total is already in operation) and to purchase a total of 125 MW of biomass generation by 2002. This year, through a competitive bidding process for the first 100 MW of new wind capacity, NSP received the industry's best price yet on wind power—about 3¢/kWh, levelized over the 30-year term of the power purchase agreement.

Paying for it

Although the price of renewables-based electricity production has dropped considerably over the past 20 years, the technologies are not yet cost-competitive enough to attract widespread interest from domestic utilities. (The situation is different in many other countries, where electricity costs are much higher than they are in the United States.) And so the question of how to ensure continued, long-term renewables investment in a competitive market still looms. Leaving it up to the handful of utilities that have faith in renewables is not enough. As industry analysts point out, it's important to create a level playing field so that a utility with a significant renewables investment does not suffer losses to a competitor who has no renewables investment and therefore has lower rates.

A couple of market-based proposals on how to achieve this level playing field have recently emerged. "While EPRI takes no position on policy options," says Birk, "we need to understand how they might influence renewable technologies in order to help members understand their technological options." One of the two new market-based concepts is called the Renewables Portfolio Standard. Developed by the American Wind Energy Association, this standard would require, as a condition of doing business in a given state, every power supplier selling at the retail level to purchase a percentage of its energy from renewable resources. Each state utility commission would determine, through public hearings, the level of renewables constituting its standard.

Any renewables-derived kilowatthours generated in excess of the state's minimum requirement could be banked for use or sale during the next year. By the same token, a supplier falling short of the minimum requirement could purchase renewables credits from another supplier. This concept of tradable credits is analogous to the sulfur dioxide emissions allowances trading established by the Clean Air Act

SACRAMENTO MUNICIPAL UTILITY DISTRICT Participants in SMUD's PV Pioneers program offer the roofs of their homes to accommodate utility-owned, grid-connected PV systems. They also agree to pay 15% more on their monthly electric bills to help support solar power.

Amendments of 1990. One significant advantage of this approach is that it helps ensure that the standard is met in the most cost-effective manner. For example, if the market price of renewables credits is less than it would cost a power supplier to acquire its own renewables generation, then the supplier would opt to purchase the credits.

Trading would be facilitated by power marketers. For example, a power marketer that had met the standard for its own retail sales could purchase additional renewables-derived kilowatthours and supply credits to the operator of a single gas plant who needed them in order to sell output to customers at the retail level. Since the standard would apply only to entities selling to retail customers, a gas plant operator that sold electricity to a power marketer or a local distribution company would not be subject to the standard.

To facilitate trading across state lines, a national clearinghouse would be established to help states track out-of-state plants and to develop common reporting guidelines. Overall, the government's involvement in the standard would be limited to monitoring compliance and facilitating trading. So far, the concept of this standard has received a favorable response. In May, for example, the California Public Utilities Commission included a portfolio standard in its restructuring proposals for the utility industry.

The second approach, advocated by the Natural Resources Defense Council, is known as the Universal System Benefits Charge. Through this mechanism, each customer's electric bill would explicitly incorporate a relatively small usage-based charge (not to exceed 5%). At each utility, the pool of money collected through this charge would become an investment fund for renewables-based generation and other beneficial systemwide programs, including energy efficiency improvements and low-income services. In the case of a charge dedicated to renewables efforts, each fund would become the basis for an auction in which renewable power providers would be invited to bid. The auction process would encourage the power providers to bid competitively. At the same time, utilities would have an incentive to acquire the most cost-effective renewables —that is, those that provide the most kilowatthours per utility dollar.

WEST TEXAS UTILITIES This PV panel powers a water-pumping system at a cattle ranch in west Texas. Under a joint venture agreement with Solamotor of Texas, WTU will install 20 such units over the next year.

NEW YORK POWER AUTHORITY NYPA owns and operates this 36-kW PV system atop Westchester County's medical laboratory and research building in Valhalla, New York. The system generates about 60,000 kWh a year.

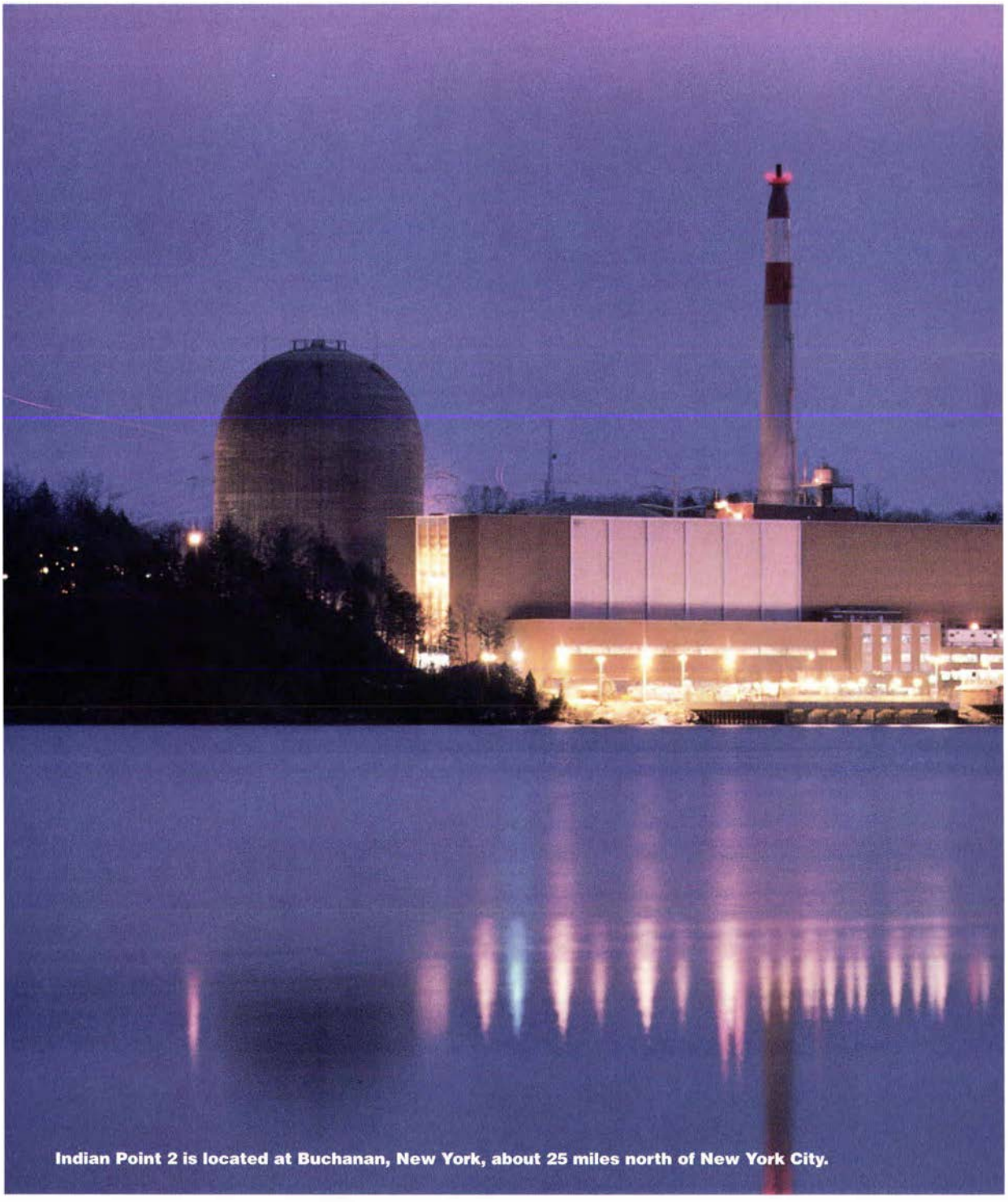
"Everyone would pay this charge regardless of the electricity supplier they select," notes Ralph Cavanagh of NRDC. "This gives the utility collecting the money the assurance that it will incur no competitive damage from these investments." Within the past year, the states of Washington and Idaho have adopted such charges to fund energy efficiency investments.

In the meantime, individual utilities are already finding that another avenue to help cover today's incremental cost of renewables is a concept known as green pricing. In green pricing, utilities obtain voluntary commitments from customers to pay higher rates to support generation by renewable technologies. The 15% premium paid by participants in SMUD's PV Pioneers program is one example of green pricing. This strategy has also recently been introduced at Detroit Edison and Public Service of Colorado. "Green pricing benefits customers, utilities, renewable technology vendors, and the renewable technology itself," says Steve Dayney of PSC, who helped devise the utility's green pricing program. "Many customers are willing to pay more than the going price for electricity to get green energy. How can a utility turn down the opportunity to get into an entirely new business at what could be no cost?"

Industry analysts agree that as supplies of fossil fuels diminish and their costs rise, renewables will ultimately become a dominant supplier of electric energy. The questions are what form the transition will take and how long it will take. "Some utilities will choose to enter this market on the ground floor," says Birk. "However, others will choose to watch, thinking that to dominate tomorrow's market they need only to cut the costs of today's power generation alternatives. The watchers may be unprepared for a future in which renewables could be thrust upon them by discount stores selling renewable energy systems for homes, by increased fossil energy costs or new taxes on fossil fuels, by international or domestic political action, or by customer demand. Obviously, the utilities that came in on the ground floor can turn these threatening situations into business opportunities." ■

Background information for this article was provided by Jim Birk of the Generation Group's Renewables & Hydro Business Unit and by Allan Hoffman of DOE's Office of Utility Technologies.

Milestone Achieved in Nuclear



Indian Point 2 is located at Buchanan, New York, about 25 miles north of New York City.

System Decontamination

THE STORY IN BRIEF The utilities that own and operate the country's commercial nuclear power plants can now have greater confidence that a complete spectrum of plant repair, life extension, and even decommissioning work is feasible, thanks to a recent demonstration involving the first full-scale chemical decontamination of a reactor coolant system. Consolidated Edison Company of New York's successful completion of the job at its Indian Point 2 pressurized water reactor during a refueling outage in March has shown the effectiveness of chemical decontamination methods and solvents in sharply reducing in-plant radiation fields and, in turn, lowering personnel exposures.

BY TAYLOR MOORE

Reducing radiation exposures among maintenance workers is a key element in the operating and maintenance costs of nuclear power plants. Although radiation fields reach a plateau after gradually rising through the early years (fuel cycles) of plant operation, plants may require more-frequent maintenance as they age.

At higher radiation field levels, more and larger work crews are necessary, and limiting personnel radiation exposures constrains plant productivity. Crews cannot stay as long in a radiation control area, and setup and cleanup requirements are much greater than they would be for the same work in a nonradioactive environment.

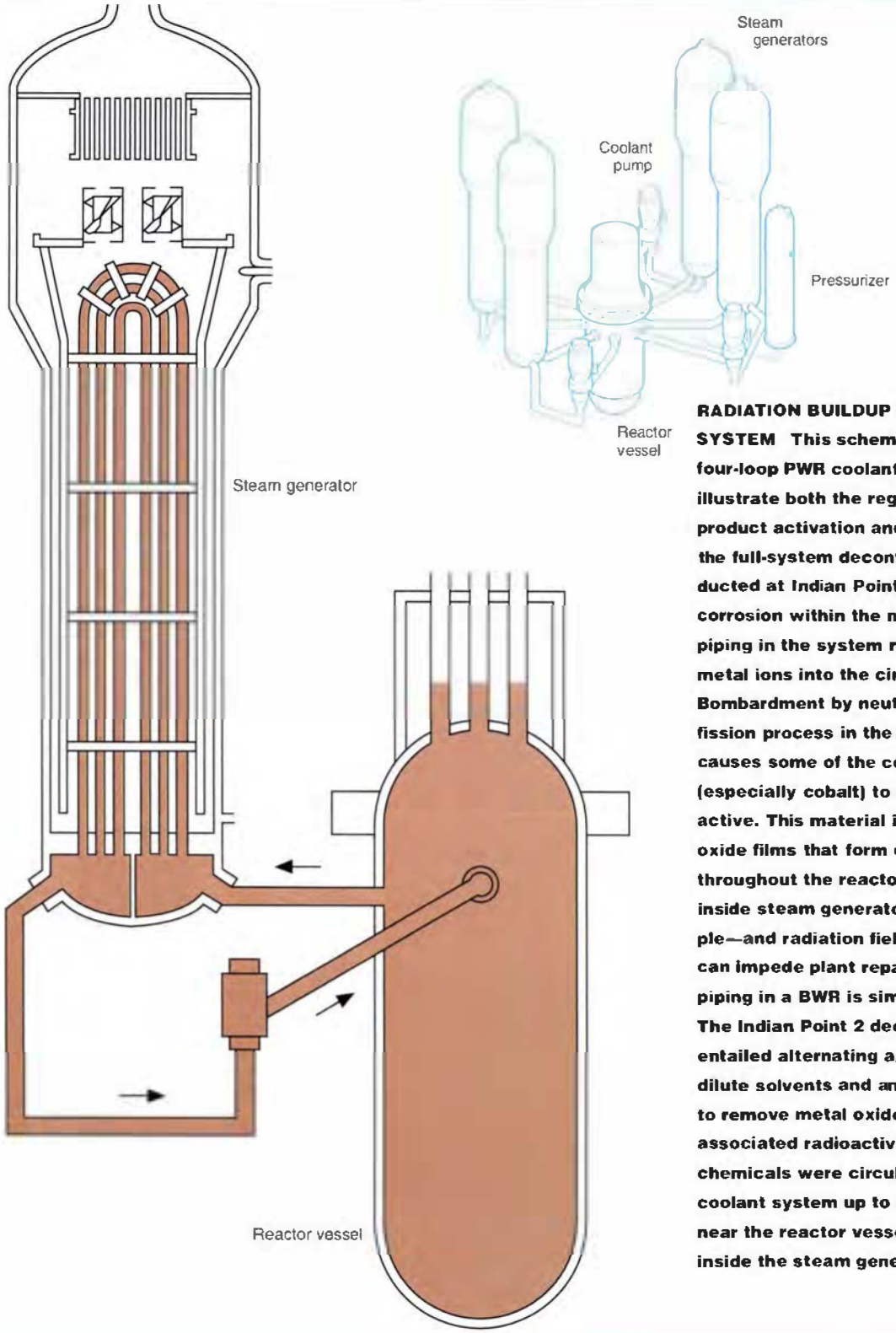
Meanwhile, limits on worker exposures are becoming ever more restrictive. On top of tighter limits already imposed by utilities, federal regulations and international guidelines for individual and lifetime personnel exposures have recently been tightened. The converging trends of shrinking exposure limits and the increased need for maintenance as nuclear plants age point to a looming potential shortage of skilled craftworkers and technicians.

Many nuclear plants have already made significant progress in reducing radiation fields and worker exposures through improved operating practices, water chemistry, and materials specification and through partial decontamination programs involving certain reactor subsystems. Now a full-system decontamination has been successfully demonstrated.

This effort, completed last March at the 975-MW Indian Point 2 pressurized water reactor of Consolidated Edison Company of New York, marked one of the largest EPRI-utility collaborations ever. It was part of an industrywide initiative aimed at de-

veloping, qualifying, and applying commercial decontamination processes for full-system use. Experts consider the Indian Point 2 decontamination a major achievement in the nuclear power industry's efforts to develop aggressive, proactive radiation management programs that will enhance plant productivity and reduce O&M costs.

The first large-scale plant cleanup removed more than 4000 curies of radioactivity from the interior surfaces of the entire primary reactor coolant system at Indian Point 2 (with the fuel removed and stored in the fuel pool). Over a nine-day period



RADIATION BUILDUP IN THE COOLANT SYSTEM **This schematic of a typical four-loop PWR coolant system helps illustrate both the regions of corrosion-product activation and the boundaries of the full-system decontamination conducted at Indian Point 2. Very slow corrosion within the miles of tubes and piping in the system releases various metal ions into the circulating coolant. Bombardment by neutrons from the fission process in the reactor core causes some of the corrosion products (especially cobalt) to become radioactive. This material is incorporated into oxide films that form on metal surfaces throughout the reactor coolant system—inside steam generator tubes, for example—and radiation fields from these films can impede plant repairs. (Recirculation piping in a BWR is similarly affected.) The Indian Point 2 decontamination entailed alternating applications of dilute solvents and an oxidizing solution to remove metal oxide films and the associated radioactive isotopes. The chemicals were circulated through the coolant system up to the level indicated near the reactor vessel head closure and inside the steam generator tubes.**

during a normal refueling outage, alternating applications of dilute solvents and an oxidizing solution were circulated with deborated coolant through the reactor at about 240°F and 190°F, respectively—temperatures that were maintained by operating three of four main coolant pumps. A skid-mounted chemical-processing system installed in the plant's auxiliary building fed the chemicals into the reactor and also received and processed the decontamination waste stream, using resin ion-exchange demineralization and filtration.

Measurements at 55 locations in the plant after completion of the job indicate that radiation field levels were reduced by an average of more than 87% as a result of the system decontamination, according to John Parry, the project manager for Con Edison. "This reduction will lead to a significant benefit in the coming years in cost savings associated with improved productivity and radiation protection and the reduced time required for maintenance work," says Parry. Con Edison estimates that the Indian Point 2 decontamination will avoid a potential 3000 rem in personnel radiation exposures over the next five operating cycles, or about 10 years.

On the basis of the better-than-anticipated results achieved at Indian Point 2, Con Edison figures that full-system decontamination could save a utility several tens of millions of dollars under certain conditions. But perhaps even more important than the specific projected savings is the value of having resolved the major engineering uncertainties regarding the feasibility of an essential technology for cost-effective plant life extension.

"As a result of the proactive approach taken by the nuclear utility industry, we now have proven technology available for controlling radiation exposures, should it be required in the future to enable major plant repairs," says Chris Wood, target leader for low-level waste, chemistry, and radiation control in EPRI's Nuclear Power Business Unit.

An industry group composed of Con Edison, Empire State Electric Energy Research Corporation (ESEERCO), EPRI, and 10 other utilities participated in an extensive program with Westinghouse Electric Corporation, the original supplier of the Indian Point 2 reactor system, to qualify the solvents that were used for the decontamination. The group also sponsored qualification work elsewhere that demonstrated that the solvents can remove radioactive-oxide contamination from the surfaces of fuel elements without damaging them. This work has set the stage for the next engineering demonstration—system decontamination with the fuel in place—which promises to maintain the substantial reduction in field levels for well beyond five operating cycles. In fact, the Indian Point 2 demonstration caps more than two decades of R&D by the participating organizations to show that nuclear plants can be effectively and thoroughly decontaminated by means of dilute chemical solvents and procedures that will not impair plant operability.

Focus on dilute solvents

Even in the very pure, demineralized borated water that circulates in a PWR, corrosion products become radioactive through bombardment by neutrons from the fission process that occurs in the core and heats the coolant. Several isotopes are created by such neutron irradiation; for the most part, these are removed through filtration and demineralization by a plant's chemical and volume control system.

The small quantities of isotopes that remain tend to form a thin layer of metal oxide on the surfaces of fuel elements, the reactor pressure vessel, and the coolant piping and in all the many inaccessible areas inside the various components that make up a PWR primary coolant system. The metal oxide layer consists primarily of iron, chromium, and nickel, but small yet radiologically significant quantities of cobalt, manganese, and zinc are also present. Two radioisotopes of cobalt—Co-58 and Co-60—account for most of the radiation fields in a typical PWR. One gram of Co-60 produces about 1100 curies of radioactivity; 1 curie generates a radiation field intensity at a distance of 1 foot of about 11 rem per hour.

Co-60 has a radioactive half-life of 5.2 years, and even minute amounts of it spread through a reactor coolant system in an oxide surface film can have a significant impact on plant operation, particularly during refueling outages. Workers are exposed when they perform routine maintenance on major plant components, including the reactor coolant pumps and steam generators. The exposure limit set by federal regulation for an individual is 5 rem per year. Most U.S. nuclear power plants, however, follow the International Commission on Radiological Protection's guidance of an average of 2 rem per year.

When Con Edison began planning the Indian Point 2 decontamination, it was envisioned as a necessary prelude to improving the plant's productivity and to possible steam generator replacement. Until recently, Indian Point 2 had high radiation field levels and the highest average personnel exposures of any PWR in the country. Moreover, in the early 1980s, steam generator replacements were entailing 2000 person-rem to do the job.

But by the time that planning for the decontamination was well along, the utility had made such progress in implementing various EPRI-developed operating practices, like improved corrosion-control water chemistry and elimination of cobalt sources, that Indian Point 2 was succeeding in efforts to reduce average plant radiation fields and worker exposures. Because chemical control and maintenance programs were successfully preserving the life of the steam generators, Con Edison projected that they would likely last through the life of the plant. Nonetheless, the utility decided to demonstrate full-system decontamination in order to significantly reduce fields and limit exposures because doing so would save O&M costs over time.

Two solvent processes were evaluated for the Indian Point 2 decontamination job: AP/CAN-DEREM and AP/LOMI. Both had frequently been used to decontaminate individual components, but neither had been applied before to an entire reactor coolant system. Both solvent processes involve the pretreatment of contaminated surfaces with an alkaline permanganate (AP) solution that further oxidizes chromium dioxide to soluble chromate and removes it, leaving the nickel and iron oxides for the solvent in the second step.

LOMI was developed earlier by EPRI and England's Central Electricity Generating Board; it has been used in over 50 applications, which account for about 90% of all decontamination work in the United States over the past decade. Utility use of LOMI is given much of the credit for reducing average nuclear plant radiation fields by half since 1984.

AP/CAN-DEREM is a modified version of a reduction process developed by Atomic Energy of Canada Ltd. (AECL) for that country's heavy-water CANDU reactors. Con Edison had funded some of AECL's original development of the process and later worked with ESEERCO in developing the AP pretreatment step. Before the full-system decontamination, the New York utility had used AP/CAN-DEREM at Indian Point 2 on three occasions for limited clean-ups. The process was used in 1989 on the plant's regenerative heat exchanger, in 1991 on the chemical volume and control system, and in 1993 on the residual heat removal system (RHRS).

Con Edison and EPRI spearheaded industry efforts that began in 1987 to determine whether either of the dilute solvents was also qualified to decontaminate a full primary system. An extensive test program was conducted for the group of sponsoring organizations by Westinghouse Electric's Nuclear and Advanced Technology Division. Westinghouse technicians took samples of all classes of alloys used at Indian Point 2 and ran them in a test loop with the candidate solvents under the same conditions and for the same lengths of time that they would experience in an actual decontamination; additional tests were conducted under more-corrosive fault conditions to demonstrate a comfortable safety margin for avoiding any damage to metal surfaces.

Engineers at Westinghouse evaluated the test results in cooperation with a utility steering committee and submitted reports on the successful qualification tests to the Nuclear Regulatory Commission. Upon review, the NRC approved both of the processes for utility use and concluded that the Indian Point 2 decontamination could proceed without a license amendment under certain guidelines.

Although both solvent processes got the green light from the NRC, Con Edison ultimately chose AP/CAN-DEREM on the basis of estimates that, for the specific conditions at Indian Point 2, it promised to cost less and produce less radwaste than AP/LOMI.

Minimizing the impact on operations

The system decontamination at Indian Point 2 was designed from the start to have the minimum possible impact on plant operations. Still, it involved operating the plant in a mode in which it had never been operated before. With the reactor defueled but the primary system at elevated temperature, plant operations during the decontamination were similar to those during hot functional testing (which is performed before the first fuel is loaded into the core and a reactor is started up for commercial operation). But Indian Point 2, even with the fuel out, contained some 4500 curies of radioactivity. The normal requirement for full containment integrity was waived by the NRC, since there was no fuel in the reactor during the procedure.

Moreover, the decontamination was in the critical path during this year's refueling outage: for several days last March, any delays or unforeseen problems with the decontamination would have held up other activities and threatened to extend the outage. During the cleanup process, the decontamination system, which was housed in a small room of the primary auxiliary building, was remotely controlled from an adjoining building. The demineralizer systems that processed the decontamination waste stream were located in the room. To coordinate the cleanup with overall plant operation, Indian Point 2 reactor operators were stationed in the adjoining building and provided a direct communication link between the decontamination system operators and the plant's central control room.

"The key questions from an operations standpoint related to how we could most efficiently and quickly give the plant over to the contractor crews to inject the chemicals and then recover the plant to a normal, borated-coolant condition, ready to load fuel back in," says John Mansell, a senior reactor operator at Indian Point 2 who was extensively involved in planning for the system decontamination and in writing the detailed plant operating procedures that guided the complex activity. Explains Mansell, "Essentially, we had to plan to come down for an outage, remove the fuel, deborate and drain the coolant, install the final pieces of equipment to do the decontamination, flood the reactor back up with plain unborated water, conduct the decontamination chemical applications, and then reborate before putting the fuel back in."

Simply deborating the reactor system's coolant, whose total volume is about 90,000 gallons, was a fairly involved procedure. Most of the coolant was drained, but some 20,000 to 25,000 gallons remained in the bottom of the pressure vessel. The coolant that could not be drained was diluted by refilling the system about halfway with pure water. After the water was mixed (by running the RHRS) and sampled, the system was redrained and completely refilled. Then the plant's ion-exchange units were used to remove the remaining boron.

Vectra Technologies was in charge of the actual decontamination work. (The company's decontamination services unit is now part of PN Services.) The contractor was required to conduct functional testing of the decontamination equipment at its facilities in Richland, Washington, and to repeat those tests after installation at Indian Point 2.

Part of the planning for the decontamination involved a program to identify all potential dead legs in the plant piping—areas of reduced flow, such as drains and instrument lines, that would be potential collection points for radioactive material—and devise methods for flushing them. The effort targeted 213 specific points, of which about 60 were successfully flushed following the decontamination.

The decontamination system's point of access to the primary coolant system was a temporary flow-control valve connection to the RHRS. This connection diverted a flow of about 1000 gallons per minute through the decontamination system and back into the RHRS. The AP/CAN-DEREM approach involves an alternating, five-step procedure of three applications of solvent and two applications of the oxidizing agent.

Each oxidation step takes up to 12 hours and each dissolution step up to 24 hours.

Two plant design modifications that were developed and tested during a 1993 refueling outage in preparation for the cleanup performed as planned. Seals for the reactor core neutron flux detector thimbles were upgraded to handle the pressures associated with system decontamination, which are higher than those reached when the thimble tubes are withdrawn during a normal outage.

The plant's reactor coolant pump seals were also tested in 1993 to determine the minimum amount of clean water necessary to protect them from the suspended particulates created during the chemical oxidation steps. The tests helped to minimize the amounts of chemicals and resin used and the amount of wastewater generated. Mansell says that coming up with an acceptable method of injecting clean water into the reactor coolant pump seals was an operational issue of considerable importance, perhaps second only to the task of defining the reactor system boundary for the decontamination.

Mansell also stresses the importance of initial decontamination equipment testing, not only under conditions expected during normal operation but also under abnormal conditions, such as reverse flow.

Joe Poplees, another senior reactor operator at Indian Point 2 who was closely involved in the system decontamination, says that a separate skid that was temporarily used to maintain primary-system pressure during the job turned out to be trickier to operate than anticipated. The system used nitrogen to maintain the pressure; in normal operation, a bubble of steam in the pressurizer fulfills that function.

Bottom line: low fields, lower exposures

Before the job was carried out, Con Edison projected that the system decontamination would achieve a decontamination factor of 5, meaning an 80% reduction in average plant radiation field levels. But in actual practice, the operation proved even more effective: the decontamination factor achieved was 7.8, for an 87% reduction in field levels.

According to Stephen Trovato, a principal engineer in Con Edison's R&D group who was involved in the work, the utility now estimates that for a typical PWR with a cycle exposure of 290 person-rem, full-system decontamination could reduce cycle exposure by more than two-thirds, or by about 200 person-rem. Con Edison estimates that first-time costs accounted for approximately two-thirds of the total project cost of $32 million at Indian Point 2. Because of the potential for further cost savings in chemicals and in waste generation, future full-system decontaminations may well cost even less than a third of that total, depending on specific circumstances.

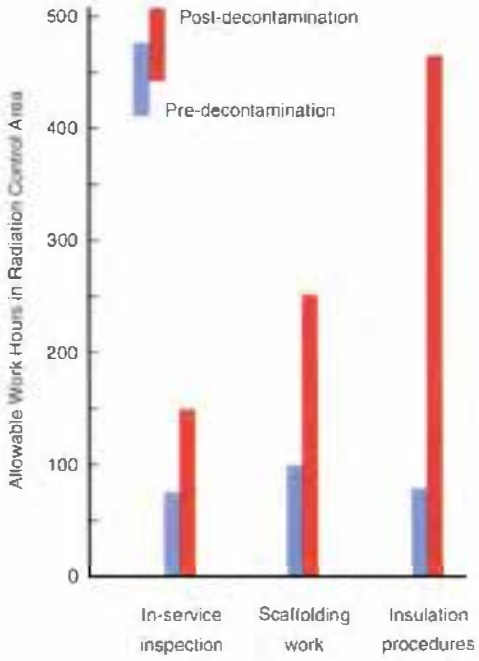
DECONTAMINATION SYSTEM EQUIPMENT **Most of the in-plant equipment used in the Indian Point 2 full-system decontamination was contained in this skid-mounted unit, shown at the vendor's facility before being installed in a small room in the power plant's primary auxiliary building. The equipment, which included demineralizer systems for processing the decontamination waste stream, was controlled remotely by operators in an adjoining building.**

Trovato says that the volume of radwaste generated as a result of the Indian Point 2 decontamination turned out to be well below the volume for which planners had accounted. An initial design estimate of 3000 cubic feet was reduced to 2400 for qualification testing and later revised downward to 2100. The actual final waste volume was 1770 cubic feet. "We think that the volume could be reduced even further by more efficient use of the resin," he adds.

Indian Point 2 is a very different plant today than it was before the decontamination, when its persistently high in-plant radiation fields necessitated locked work areas within the containment. Now, says Poplees, "when I go into the plant, I can work near valves and piping that I haven't seen in about 10 years because they were always wrapped in lead or hidden behind water shields. Much more of the plant is accessible, and we need fewer people and spend less time hanging shielding." Poplees says that he is now able to perform a hydroflush check-valve test directly underneath the loop piping, rather than remotely from behind a wall, thanks to the lower field levels in the plant.

The post-decontamination field levels simplified a variety of tasks during the remainder of the refueling outage and made them less costly in time and exposures. "The inside crane wall was no longer a locked high-radiation area, which was phenomenal," says Poplees. "We had free access to it and didn't have to get a health physicist to escort us to open doors and so forth, which speeded things up tremendously." He notes that field levels were so reduced inside the steam generators that workers were able to modify them to accept nozzle dams, which make it possible to flood the reactor coolant system for refueling and work on the steam generator tubes at the same time.

THE PRODUCTIVITY PAYOFF The lower in-plant radiation fields resulting from the full-system decontamination at Indian Point 2 translate into substantial productivity improvements and exposure dose savings among plant maintenance workers. For selected tasks, Con Edison has compared productivity before the March 1995 decontamination with that following the work. These preliminary comparisons show large increases in productivity, as measured by the number of hours a work group could perform in a radiation control area before collectively receiving 1 rem of exposure.



If there was any uncertainty regarding the estimated dose savings at Indian Point 2 as a result of the system decontamination, preliminary comparisons of actual work productivity in some selected tasks confirm expectations of substantial improvements thanks to the lower field levels. Con Edison's John Parry says that comparisons of the hours worked in the radiation control area for certain job categories during the plant's 1993 outage and during the 1995 outage (after the plant cleanup) show productivity improvement factors of 2–4; in some cases, the improvement was even greater.

Parry cites two examples: the workers who take down reactor piping insulation and reinstall it after work is done and the workers who erect and disassemble scaffolding. Before the decontamination, the insulation group could get in about 70–80 hours of work before collectively accumulating 1 rem; after the decontamination, over 450 hours of work were done before the group received 1 rem of exposure. The scaffolding workers previously could receive 1 rem in less than 100 hours of work; now they are able to work almost 250 hours before they receive 1 rem.

What's next

From the perspective of engineering R&D, the next step is for a utility to demonstrate a full-system decontamination with the fuel remaining inside the reactor. Although operationally a fuel-in decontamination might be very similar to a fuel-out process, the planning required would be more extensive; the amounts of chemicals needed and the waste generated could be greater or less, depending on the solvent process used.

Fuel-in system decontamination offers two principal advantages, according to EPRI's Chris Wood: "First, it can take the job off the critical path of a refueling outage because the decontamination can be conducted while the plant is cooling down for refueling. Second, decontaminating the fuel element surfaces will virtually eliminate any recontamination due to fuel crud that would eventually result with a fuel-out decontamination."

On the basis of earlier, partial decontaminations at Indian Point 2, Parry says, Con Edison expects that recontamination rates from the two-thirds core load of irradiated fuel reloaded into the reactor will be substantially lower than previously predicted, and that the plant will enjoy an operating benefit in reduced field levels and worker exposures well beyond the projected five fuel cycles. "Between the system decontamination itself and the industry's improved knowledge of how to operate plants to keep dose rates and exposures low, I personally don't think we will ever return to our original dose rates."

Wood notes that EPRI, Westinghouse Electric, and South Carolina Electric & Gas Company qualified both the CAN-DEREM and LOMI processes for use on fuel in closed-loop tests recently at the utility's V. C. Summer plant. The tests used the solvents to effectively remove surface oxide film from real assemblies with no damage or ill effects. "We're now in a position to include the fuel in the next system decontamination," says Wood.

EPRI and the utility industry may also be in a position to demonstrate full-system decontamination in a boiling water reactor, for which much of the plant engineering would be significantly different (although the decontamination process equipment would, for the most part, be similar). Utility companies in Sweden have demonstrated an incremental system decontamination at the Oskarshamn BWR with the fuel removed. But there is uncertainty about the actual cost of a BWR full-system decontamination in this country, and U.S. utilities so far have taken the line that partial-system decontamination that focuses on removing radioactive crud from the bottom of a BWR pressure vessel is sufficient to achieve a substantial plant decontamination factor.

"In the cost-conscious environment of today's increasingly competitive electricity industry, it may be difficult for a utility to justify the cost of a system decontamination solely on the basis of exposure savings and avoided O&M costs over the long term," says Wood. "But considered in the context of a possible major plant repair, like a steam generator replacement or work within the pressure vessel, full-system decontamination is now a proven, demonstrated technology that could well yield immediate dividends as well as longer-term benefits." ■

Background information for this article was provided by Chris Wood of the Nuclear Power Business Unit.

CONTRIBUTORS

Technical sources for Journal feature articles

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Global Climate Research: Informing the Decision Process (page 6) was written by science writer John Douglas, with background information from four members of EPRI's Environmental & Health Sciences Business Unit.

Richard Richels, Technical Executive and target leader for EPRI's global climate change research, joined the Institute in 1976 and has directed a number of EPRI's energy analysis, environmental risk, and utility planning research activities. He was previously a consultant to the Rand Corporation and the National Science Foundation. Richels holds a BS degree in physics from the College of William and Mary and MS and PhD degrees from Harvard University.

Tom Wilson is a technical manager for energy analysis issues in EPRI's global climate change target. His present work focuses primarily on utility decision-making and reporting methodologies for greenhouse gas issues and on identifying least-cost global atmospheric stabilization strategies. Earlier he managed projects related to risk management and decision methodologies for a variety of environmental issues. Before coming to EPRI in 1985, Wilson worked at ICF Incorporated, Stanford's Energy Modeling Forum and International Energy Program, and Brookhaven National Laboratory. He holds a BS in statistics from the University of North Carolina at Chapel Hill and MS and PhD degrees in operations research from Stanford University.

Louis Pitelka, a technical manager for ecological studies in EPRI's global climate change target, is currently responsible for projects addressing the effects of elevated carbon dioxide levels and climate change on terrestrial ecosystems and global carbon cycling. Before joining the Institute in 1984, he was director of the Population Biology and Physiological Ecology Program at the National Science Foundation. Before that, he taught at Bates College and chaired the biology department there. Pitelka received a BS in zoology from the University of California at Davis and a PhD in biological sciences from Stanford University.

Chuck Hakkarinen is a technical manager for atmospheric sciences. His current projects address climate change (including work on the Model Evaluation Consortium for Climate Assessment), plume dispersion, and plume downwash modeling. He has managed various projects and programs in the environmental sciences since coming to EPRI in 1974. Hakkarinen received a BS in mathematics and an MS in meteorology from the University of Maryland and a PhD in environmental science and engineering from UCLA. ■

Renewables in a Competitive World (page 16) was written by Leslie Lamarre, *Journal* senior feature writer, with background information from **Jim Birk,** manager of EPRI's Renewables & Hydro Business Unit, and **Allan Hoffman,** associate deputy assistant secretary for utility technologies at the U.S. Department of Energy.

Birk came to EPRI in 1973 as a project manager for advanced battery development and assumed increasing levels of responsibility in energy storage, ultimately overseeing research in hydropower and renewable technologies as well. His earlier experience includes seven years as a senior scientist with Rockwell International Corporation. During that time Birk spent a year on loan to Argonne National Laboratory, working on the development of advanced battery technologies. He received a BS in chemistry from Iowa State University and a PhD in analytical chemistry from Purdue University. ■

Milestone Achieved in Nuclear System Decontamination (page 26) was written by Taylor Moore, *Journal* senior feature writer, with information and guidance from **Chris Wood,** target leader for low-level waste, chemistry, and radiation control in EPRI's Nuclear Power Business Unit. Wood joined EPRI in 1982 after 14 years as head of the radiation chemistry section in the R&D department of England's Central Electricity Generating Board. He holds the patent for the LOMI chemical decontamination process. Earlier he worked for four years as a research chemist at E. I. du Pont de Nemours & Company. Wood received a BS degree in chemistry from University College, London, and a PhD in physical chemistry from Leicester University. ■

EPRI and Eskom Form African Centre for Essential Community Services

EPRI and Eskom, the South African utility, are establishing the Centre for Essential Community Services (CECS) to bring to the people of Africa opportunities for greater electrification and for greater application of beneficial electrotechnologies, especially those that help supply clean water and improve health conditions. Eskom is the world's fifth largest electric utility, supplying more than half of Africa's total electricity.

The primary role of the CECS will be to act as a technology transfer mechanism for moving EPRI technology through Eskom into sub-Saharan Africa. Its work, which will also include project management, will be closely coordinated with government objectives and will initially focus on water purification, health care, and the role of electricity in these areas. The CECS credo—For Technological Contribution to the Greater Population's Health and Well Being—is intended to closely align with the goals of the South African government's Reconstruction and Development Program (RDP), which focuses on water and electricity supplies and health care issues.

The CECS will function as a satellite of the EPRI Customer Systems Group's Community Environmental Center in St. Louis, Missouri, and will be part of the Institute's center and office network. Official EPRI participation and support will involve technology transfer, shared projects, and project management.

"We are pleased that this Eskom partnership gives us greater opportunity to apply technology for improving the quality of people's lives," stated EPRI's Clark Gellings, vice president for the Customer Systems Group and a member of a recent U.S. energy delegation to the Republic of South Africa. The mission on sustainable energy and trade, led by U.S. Secretary of Energy Hazel O'Leary, visited South Africa for a week in August at the invitation of President Nelson Mandela.

Initially, the CECS will be supported by EPRI and Eskom. Additional funding is expected from the South African government, the South African water utilities and health care industries, and other interested parties. After the first three years, the CECS is expected to be self-supporting and will function as a not-for-gain South African corporation.

The host site for the CECS, most likely a major South African university, will be selected through a request-for-proposal process. Selection criteria include technical capabilities, community presence, ties to key South African industries, and resource contributions.

Commenting on the plans for the CECS, which follow a year-long partnership in which Eskom and EPRI explored collaborative R&D opportunities in a variety of technologies, Eskom's Steve Lennon said, "The challenges faced by the Republic of South Africa are numerous, particularly in the effort to improve the lot of the general populace. The African Centre for Essential Community Services will be a key element in supporting the South African government's objectives under the RDP: electrification, adequate water supplies, and improved health and health care for the citizens of South Africa. Eskom is proud to be part of this work and to partner with EPRI."

EPRI Tapped to Design Real-Time Networks for Transmission Access

The Federal Energy Regulatory Commission has asked EPRI to help achieve a utility industry consensus on how to implement real-time information networks (RINs) for transmission access. EPRI is assisting in a cooperative industry effort to provide input for a supplemental notice of proposed rulemaking (which FERC says it plans to issue by late 1995) mandating requirements for RINs.

In the emerging competitive market for electricity, RINs would be used by both utilities and wholesale customers to share information on open-access transmission tariffs. FERC's stated intention is that RINs be in place by the time a final rule on open-access transmission goes into effect, which is expected sometime in 1996.

As a result of an industry consensus expressed at a FERC conference in July, EPRI is cooperating with the North American Electric Reliability Council, individual utilities, and others in defining the technical requirements of RINs. NERC is facilitating a working group on what information RINs should include, while EPRI is facilitating a working group focused on how RINs should be implemented.

The EPRI-facilitated working group, composed of experts from various segments of the electric utility industry and from related industries, guided the development of a draft report during two workshops in September and October. Also, a survey of transmission-owning utilities was conducted to document RIN implementation activities and plans nationwide. A final report combining the survey and workshop results was to be submitted to FERC by mid-October.

Implicit in FERC's proposed supplemental notice is a recognition that RINs may require a standard communications protocol. Industry agreement on the information content of RINs and on a standard protocol for sending and receiving such information could enable different types of RINs to coexist and work together.

On behalf of the electric power industry, EPRI has already made the second requirement practical with the recent completion of the Inter-Control Center Communications Protocol (ICCP) for real-time data exchange between control centers, power pools, and utility business centers. EPRI is working with NERC and others to develop, on the basis of the same standard, a simplified communications protocol for RIN applications that do not need the full functionality of ICCP.

ASME Awards EPRI Manager the George Westinghouse Gold Medal

Thomas McCloskey, manager for turbomachinery in EPRI's Generation Group, is the 1995 recipient of the George Westinghouse Gold Medal Award, bestowed each year by the American Society of Mechanical Engineers "for eminent achievements in the power field of mechanical engineering." The award, presented to McCloskey in October at the International Joint Power Generation Conference in Minneapolis, Minnesota, is in broad recognition of his contributions over a 25-year career in power-related R&D.

McCloskey has been a pioneer in the inception, development, and application of several innovative technologies, including erosion- and corrosion-resistant turbine blade coatings, active magnetic bearings, and finite-element stress and fracture computer codes for life assessment and efficiency improvement of turbomachinery blades and rotors. These and other innovations have been applied in more than 100 electric utility power plants worldwide, resulting in over $1 billion in savings to the industry.

Before joining EPRI in 1980, McCloskey worked 11 years as a project engineer and manager at Westinghouse Electric Corporation, where he was responsible for the design of both fossil and nuclear steam turbines up to 1300 MW. He holds six patents in mechanical engineering and steam turbine design. McCloskey is a fellow of the ASME; codirector of the ASME Steam Turbine Short Courses on Design, Operation, and Maintenance; and past chairman of the ASME Steam Turbine Committee. He graduated in mechanical engineering from Drexel University.

McCloskey's present responsibilities include R&D related to the thermal performance, availability, and life assessment of steam and combustion turbines, pumps, and fans. He is a technical consultant to over 100 electric utilities, original equipment manufacturers, and service organizations worldwide and has written over 60 technical papers on power plant performance and on steam and combustion turbine generator availability, life extension, and thermal performance improvements.

Puget Power Develops Comprehensive Underground Cable Life Program

Puget Sound Power & Light Company is taking a comprehensive approach to life extension for underground residential distribution (URD) cable. The program uses EPRI research results and recommendations on cable specifications, manufacturing procedures, and operating practices. As a result of the improvements achieved with the approach, Puget Power expects its newly installed URD cable to last a minimum of 10 additional years, for present-value cost savings of $54 million to $77 million over the next 30 years, depending on load growth.

"EPRI research, seminars, and consultations have enabled us to identify and implement procedures we feel confident will ensure maximum performance of newly installed cable, thereby reducing our operating expenses and improving customer service," says the utility's Push Patel.

In the 1980s, Puget Power began to notice an unusually high premature failure rate for the high-molecular-weight polyethylene URD cable it had installed in the 1960s and 1970s. Concern grew as the failure rate increased over the next few years.

But as EPRI research on URD cable failure and life extension began to produce results in the late 1980s, Puget Power stayed abreast of the latest findings through its involvement in EPRI projects and seminars and through relationships developed in day-to-day consultations with EPRI personnel. By 1994, the utility had developed a comprehensive cable life extension program that included the use of solid-conductor, jacketed cross-linked polyethylene cable with tree retardant; triple extrusion and dry curing of cable during manufacturing; periodic quality assurance audits of the cable-manufacturing process; and elimination of testing procedures and operating practices found to damage cable.

EPRI research with materials suppliers, cable manufacturers, and utilities is leading to significant reductions in utility investments in cable replacement and cable operating and maintenance costs. The two-volume *Distribution Cable Research Digest* (EL-6271), available through the EPRI Distribution Center, documents the research results and outlines recommendations.

■ *For more information, contact Ralph Samm, (415) 855-2289.*

Research Network Helps Georgia Power Prime the EV Market

Atlanta, the site of next year's summer Olympics, is one of 22 U.S. cities facing the challenge of achieving the mandates of the 1990 Clean Air Act Amendments. Pollution sources in Atlanta's service-oriented economy are highly dispersed, with internal combustion engine automobiles one of the key contributors to ozone nonattainment. The typical climate of high humidity and high temperatures exacerbates the city's air pollution.

In 1992, after determining that electric vehicles (EVs) could contribute significantly to solving Atlanta's environmental dilemma and potentially expand the market for off-peak electricity, Georgia Power Company launched a program to demonstrate the efficiency and viability of this emerging transportation technology. Around the same time, the utility joined EPRI's Electric Vehicle Research Network (EVRN) in order to participate in joint research on EVs and to access EPRI expertise.

As a participant in the EVRN, Georgia Power has an avenue for conducting highly targeted research and for working with a variety of other organizations to foster technology development. The utility estimates that its involvement with the research network leverages a $150,000 investment into services worth more than $500,000.

In 1993, Georgia Power opened its Electric Vehicle Research Center, which is housed at SciTrek, a science and technology museum adjacent to the utility's corporate headquarters. Visitors to SciTrek can see a working EV laboratory—a facility where Georgia Power tests EVs, batteries, charging stations, and related components under a wide range of operating conditions. Through the center, the utility is working to educate consumers and dispel myths about EV technology and is also learning about the true potential for EVs to meet customer transportation needs in the Atlanta area.

As a participant in the Chrysler TEVan project, Georgia Power bought 10 of the first production-line EVs in the country and now uses the vans in its fleets and in public demonstrations. The TEVan is expected to see commercial operation in utility and government fleets. A market penetration of 500,000 EVs in a utility service area over the next 20 years could translate into more than 1.6 million MWh in new off-peak electricity sales.

"Georgia Power is taking steps to help advance electric vehicle technology by working to increase public awareness and acceptance of electric transportation," says company representative Marie Mouchet. "We're proud to be playing a key role in this exciting new industry—an industry that could bring more jobs and economic opportunity to Georgia and provide environmental benefits to our nation."

■ *For more information, contact Layla Sandell, (415) 855-2756.*

EV testing at Georgia Power's Electric Vehicle Research Center

Power Quality

Customizing Adjustable-Speed Drives for Injection Molding

by Marek Samotyj, Power Quality Business Unit

Adjustable-speed drives (ASDs) provide high-performance control and also energy savings for such loads as pumps, fans, and blowers. The success of ASDs in these applications has led to their widespread acceptance and use.

In contrast, ASDs are not widely used in complex processes like plastic injection molding. Moreover, the requirements for implementing them in such processes are not well understood, and the benefits are not well documented. Given the complexity of injection molding, it is not possible to purchase off-the-shelf ASDs and plug them into the manufacturing process. Attempts to do so have led to disappointing results. However, the outstanding control and energy savings provided by ASDs in other applications have led industrial customers to continue to look for ways to successfully introduce ASDs into more-demanding processes.

Against this backdrop, Potomac Edison Company—part of Allegheny Power System (APS)—hosted a seminar that brought together one of its customers, Automotive Industries, and an ASD vendor. The vendor identified substantial potential economic benefits of using ASDs with large injection mold machines. A trial drive had been installed, and savings were demonstrated. Realizing the energy efficiency potential of the ASD retrofit, Potomac Edison contracted with EPRI's Adjustable-Speed Drive Demonstration Office (ASDO), an applications center of the Power Quality Business Unit, to assist with the planning and engineering necessary for a full-scale effort.

The practical problems of customizing ASDs and of determining the overall benefits of applying ASDs in the highly complex injection-molding process were challenges that APS, Automotive Industries, and EPRI's ASDO were eager to meet. Although the focus of the study, which started in late August 1993 and was completed in January 1995, was to investigate and document both the energy and nonenergy benefits of using ASDs, one of its most practical and immediate results has been the development of a method for customizing ASDs to fit into such a complex process.

Injection mold machines

To demonstrate the systematic use of ASDs with the hydraulic pumps in injection mold machines, APS and Automotive Industries selected a group of seven mold machines connected to a single supply transformer.

In the injection-molding process (Figure 1), raw material is supplied to a mold machine in granular form. Typically the bulk feed material is colorless, and color pellets are metered into it at the mold machine. This colored feed material is transferred to the mold via a screw feeder that is surrounded by electric heater bands. As the material moves through the screw feeder, it is heated to a temperature that ensures the correct fluid viscosity for injection molding. A mechanical ram is used to inject the material into the mold at high velocity and to hold the pressure until the material has flowed into all sections of the mold and has set. Once the part has cooled sufficiently to be handled, the mold is opened and the new part removed. The mold is reclosed so that the process can be repeated.

Hydraulic rams and motors are used to accomplish the mechanical actions required to move the feed material; open, close, and lock the mold; inject the feed material; and eject the part. Hydraulic power is flexible, and many actions can be initiated independently by any of several parallel hydraulic pumps. Each injection mold machine involved in this study has multiple electrically driven hydraulic pump units. Each electric motor drives two vane pumps, one at each end of the motor.

Applying ASDs in a complex process

Unlike more-typical ASD applications, controlling hydraulic pumps with ASDs involves multiple inputs and feedback loops. In order to produce high-quality molded parts, the entire mold is cooled by chilled water.

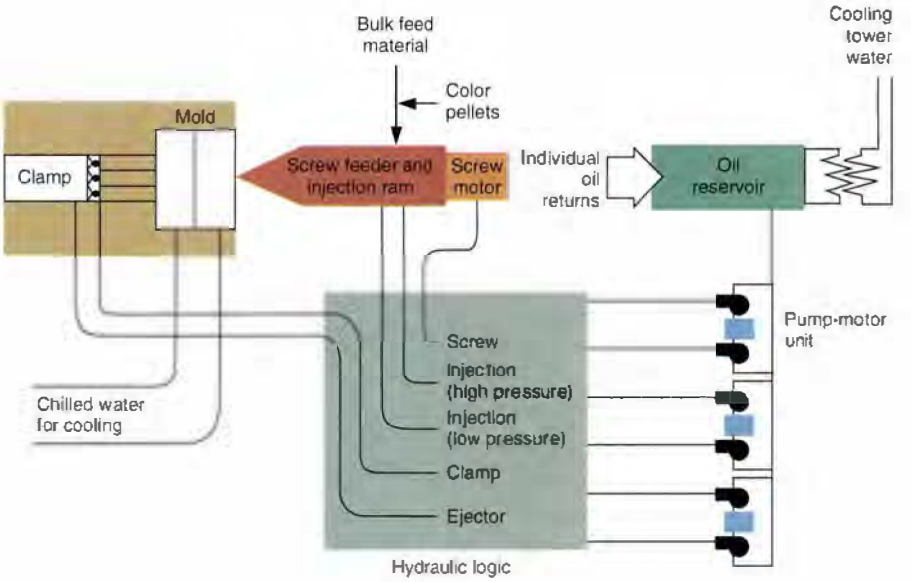
ABSTRACT *In an applied research effort by a team of participants from the utility industry, an industrial customer, vendors, and EPRI's Adjustable-Speed Drive Demonstration Office (an applications center of the Institute's Power Quality Business Unit), it was shown that adjustable-speed drives can be successfully applied in the complex process of plastic injection molding. An important result of this effort was the development of a practical and repeatable method for customizing ASDs. In addition, both energy and nonenergy benefits of using ASDs were measured and documented.*

However, the heat profile across the surface of the mold must be correct for the particular mold shape. This requires having a complex arrangement of rod heaters in some areas of the mold and supplying supplemental chilled water in other areas. Temperature and pressure are constantly monitored throughout the injection-molding system, and all components of the system must work together effectively. The molding process is further complicated by the need to dry the incoming granular materials and the need to grind up parts produced during machine startup that do not meet the high quality standards.

One of the practical problems faced by the project team was to develop a method that would help ensure the successful introduction of ASDs into the injection-molding process. With substantial input from EPRI's ASDO, the team developed a five-phase method for customizing ASDs for a particular system. The phases, described below in detail, are as follows:

- Specifying the system
- Selecting the vendor and establishing responsibilities
- Installing the equipment
- Testing, starting up, and operating the drives
- Training the workforce

Figure 1 A typical injection-molding system features multiple hydraulic pumps driven by electric motors. Each pump can control any of the mechanical actions required in the molding process (e.g., injecting the feed material into the mold). A project at an industrial customer of an EPRI member utility has demonstrated the benefits of using adjustable-speed drives in plastic injection molding and has developed a method for customizing ASDs for such complex applications.



Phase 1: specifying the system

The all-important basis for implementing ASDs in a complex process is to understand that the drives must be part of the system and to understand how the system's components work and interact. This knowledge is developed over several steps in phase 1 of the method.

The first step is to identify the system's components. In this project, the team identified four major components: the driven equipment, the motors, the ASDs, and the power system, including both the internal distribution system and the utility power supply.

The second step in the specification phase is to analyze interacting components. Using three criteria—power quality, energy efficiency, and control effectiveness—the project team determined how the four major components needed to work together as a system to enhance the injection-molding process. That activity required a systems engineering perspective and was critical to all later phases of the project.

The third step is to identify loads that can benefit from ASD control. As a way to distinguish hydraulic pumps with high potential for savings from those with low potential, the project team measured the power consumed by each pump-motor unit. Typical of the motors not suitable for retrofit are those in booster pump applications. Booster pumps operate at full pressure for a small portion of the total cycle time. For the remainder of the cycle, they are bypassed in order to achieve higher energy efficiency. In contrast, pumps suitable for retrofit are those that have high annual operating hours and whose output capacity can be reduced and still meet the mold machine requirements. The hydraulic pumps and motors selected for ASD retrofit in this project had substantial load throughout the injection-molding cycle, with more than 3500 operating hours per year.

The fourth step in specifying a system is the creation of detailed technical documents. After the team completed its analysis of the total injection-molding system, EPRI's ASDO prepared detailed technical specifications that covered requirements for mold machines, ASDs, and system coordination, as well as performance guarantees and turnkey execution of the retrofit.

The fifth and final specification step is to identify equipment costs. In this project, four types of costs were identified: ASD equipment, control system, installation, and engineering.

Phase 2: vendor selection

A request for proposals that incorporated the ASD system specifications was prepared by Automotive Industries and sent to three vendors. The criteria for selecting a vendor included experience with ASD equipment on mold machines, knowledge of electric power system engineering, installation experience in a plastics manufacturing environment, and skills to train machine operators.

During the system specification process, it was decided that a single vendor would be responsible for the complete retrofit. The following responsibilities and requirements were spelled out:

- Produce quality parts with mold machines under ASD control at the same rate as produced by machines under fixed-speed control
- Achieve stated energy savings goals

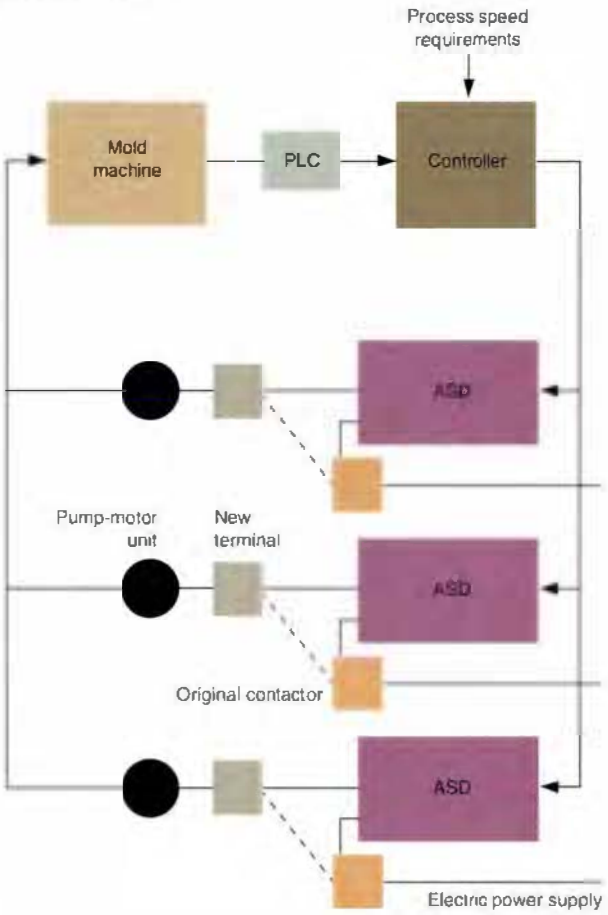
- Comply with IEEE 519-1992, which sets harmonic voltage and current standards
- Ensure that there is no interference between the ASDs and the existing plant electric power system and guarantee that electrical coordination is maintained
- Achieve performance guarantees in power savings, harmonic injection, motor life, and ASD reliability
- Integrate the retrofit smoothly with the production requirements
- Take responsibility for all aspects of installation, including equipment, materials, labor, and logistics
- Train operations personnel at the time of installation and also at six-month intervals over a period of two years following ASD startup

Phase 3: installing the equipment

Sixteen ASDs were installed in late December 1993 and early January 1994. By the end of the first week in January, the equipment was ready for startup.

To facilitate rapid bypass of the ASDs for installation testing and maintenance, a terminal block was installed to terminate the original motor cables. This enabled the motors to be fed from either the ASD or the conventional electric power supply.

Figure 2 In the demonstration project, ASDs were implemented on the existing pump-motor units of several injection mold machines. One such setup is shown here. Speed requirements for each stage of the process cycle are entered into the controller, which communicates them to all the ASDs for the mold machine; subsequent cycles can be modified on the basis of feedback from the machine via a programmable logic controller (PLC). A terminal installed on each pump-motor enables it to be fed from either the ASD or the conventional electric power supply.



Phase 4: testing, startup, and operation

Key production personnel arranged the setup of the mold machines, adjusting flow control until quality parts were produced. Each machine has either two or three pump-motor units, each of which is controlled by an individual ASD (Figure 2). The ASDs are provided with the same digital speed reference to ensure that the hydraulic load is shared by the hydraulic pumps during each part of the injection-molding cycle.

Speed requirements for each stage of the process cycle are entered on the keyboard of the common controller. Once entered, the information is distributed to all the ASDs for a mold machine via a serial communications link. The ASDs use this information to control all subsequent molding cycles. At any stage in the production cycle, an update for all or subparts of the cycle can be sent to the drive system. This gives the key production staff great flexibility in setting up a mold machine.

Complete sets of mold machine information can be stored in the controller memory, facilitating rapid setup of a machine. Since the setup process does not involve flow constriction devices to achieve control, the results are repeatable. Tests were conducted to study the consistency of ASD control.

Startup and operation did not proceed without some interruptions. Early in the testing of the ASDs, it became evident that a number of the drives were intermittently tripping on overcurrent. The ASD manufacturer determined that the drives did not meet the specifications on overcurrent capability, and new ASD equipment was promptly installed that completely resolved the sporadic nuisance tripping. However, the experience temporarily shook the confidence of the customer's engineers and machine operators.

Shortly afterward, there were problems with the liquid crystal displays used in setting up the drive parameters. The controllers were identified as the cause of the problem, and within one week all two-layer PCB versions were replaced with four-layer PCB versions.

Since March 1994, the ASD systems have been extremely reliable. To date, no further problems have been experienced with the drive systems.

Phase 5: training the workforce

To ensure efficient use of the equipment, the specifications explicitly stated that Automotive Industries operations personnel be trained at the time of installation and also at six-month intervals over a period of two years following the startup of the ASDs. In addition to presenting in detail the operations of the new equipment, the training helped to instill confidence in the workforce, allowing a smoother integration of the ASDs into the work process.

ASD benefits

Although this article has focused on the customization of ASDs, a key part of the research involved measuring and documenting both the energy and nonenergy benefits of applying ASDs in the injection-molding process. In July 1994, detailed and carefully controlled tests using a wide variety of measurements were carried out to gather data on the injection-molding

process both with and without ASDs.

With ASD control, the electric energy use of the seven mold machines' pump-motors was reduced by 38% (which represents a 23% reduction in the total electric energy use of the mold machines). The revolutions per minute of the pump-motors were reduced by 40%, which translates into a large increase in expected service life, and their noise was reduced by 6 dBa. Mold machine setup time was significantly reduced by using the memory feature of the control system. Finally, harmonic concerns were addressed in the total system installation, and the IEEE 519-1992 guidelines were met without significantly affecting costs.

In short, in an applied research effort that produced practical, immediately applicable results for the utility industry and its customers, the project team demonstrated how ASDs can be customized and how they can be applied efficiently and effectively in the highly complex process of plastic injection molding. These results, including the ASD specifications, are presented in EPRI report TR-105149.

Air Quality

Air Toxics: Atmospheric Fate of Trace Substances

by Mary Ann Allan, Environmental & Health Sciences Business Unit

Utilities need to assess the risk posed by their air emissions, including the trace substances referred to as air toxics or hazardous air pollutants (HAPs). In the 1990 Clean Air Act Amendments (CAAA), Congress instructed the Environmental Protection Agency to study the risk posed by power plant trace substance emissions and to make recommendations for an appropriate management strategy. In addition to possible federal regulation under Title III of the CAAA, a number of states and other government bodies have already established trace substance programs or are actively considering such action to address regional concerns.

As the EPA acknowledged in its recently drafted report to Congress, assessing the risk posed by power plant trace substance emissions is very complicated. These substances are emitted in such small amounts that accurately measuring emission rates has been made possible only by the recent development (by EPRI and others) of new techniques for sampling and analysis. To further complicate the task, researchers have found that some of the substances of most concern, such as mercury, can be emitted in a number of chemical and physical forms—forms with distinct characteristics that affect how well the substances are captured by pollution control equipment, their rate of removal from the atmosphere, and their potential toxicity.

EPRI has been carrying out a broad research program designed to provide timely information to utility managers and environmental regulators as they evaluate the risk from power plant trace substance emissions. Much of the knowledge gained has been incorporated in the EPA's report to Congress. Ongoing research will supply critical information, enabling those charged with managing air quality to make informed decisions and helping those responsible for implementing policy to do so effectively. The following key questions are being addressed by this research:

- Which, if any, trace substances emitted by power plants pose a significant health risk?
- How are utility and nonutility emissions related to environmental levels?
- How do trace substances change in the atmosphere, and how are they transported and deposited in ecosystems?
- What are the spatial and temporal scales of the relevant processes?
- How will a change in emissions at a particular source or number of sources influence exposure at a given location?

To answer these questions, policymakers and utility managers need reliable instruments and techniques for quantifying emissions, ambient concentrations, and the deposition of important trace materials. Also needed are reliable models for relating emissions to subsequent ecosystem or human exposure so that, if necessary, effective control strategies can be crafted and eval-

ABSTRACT *Understanding the atmospheric processes that control the cycling of trace substances emitted from power plants is essential in evaluating the health risk posed by these potentially toxic materials. EPRI's research is improving estimates of the quantities of trace substances emitted, examining the form in which the substances are released and the physical and chemical changes they undergo in the atmosphere, and determining how they are deposited in ecosystems.*

uated. The development of such models requires a vastly improved understanding of the atmospheric processes that control the transport, transformation, and ultimate deposition of trace substance emissions. This update reviews EPRI's atmospheric sciences research on trace substances, with a focus on mercury.

TABLE 1
Power Generation Emissions Estimates

Substance	*U.S. Utility Emissions (short tons/year)*	*Percentage of Total Anthropogenic Emissions**
Arsenic	121	3.0
Beryllium	13	NA
Cadmium	12	0.2
Chromium	89	0.6
Hydrogen chloride	309,027	NA
Lead	103	0.1
Manganese	187	0.2
Mercury	47	27.0
Nickel	391	6.0
Selenium	786	69.0

*Total anthropogenic emissions are based on known sources and could be underestimated. Many nonutility source categories remain highly uncertain. NA (not available) indicates that the percentage could not be calculated because of a lack of data. Estimates for the nonutility sources of arsenic, cadmium, chromium, lead, manganese, nickel, and selenium are based on total suspended particulate emissions in the 1985 National Acid Precipitation Assessment Program inventory.

Quantifying emissions

The first obstacle to quantifying the risk from power plant trace substance emissions is determining just how much of each substance is emitted—and in what chemical and physical forms. Initial estimates based on mass balance considerations suggested that utilities emit about 25 of the 189 substances designated in the 1990 CAAA as HAPs. While EPRI's Generation Group focused on quantifying utility industry emissions of trace substances through its PISCES (Power Plant Integrated Systems: Chemical Emissions Study) effort, the Environment Group conducted atmospheric research to develop an emissions database for all anthropogenic sources. In this way, utility emissions could be shown in perspective with all other emissions sources. On the basis of a screening review of the magnitude of utility stack emissions and associated human health risks, the list of trace material "suspects" was narrowed to 10 priority substances of concern: arsenic, beryllium, cadmium, chromium, hydrogen chloride, lead, manganese, mercury, nickel, and selenium.

Given this list of high-priority trace substances, ENSR Consulting and Engineering undertook research to develop emissions estimates on the basis of existing data. Information on the composition of coal actually consumed by power plants was combined with knowledge about combustion kinetics and control equipment capture to improve on previous mass balance estimates. Data from PISCES served as the backbone for estimates of utility emissions, while data and reports from the EPA and others provided estimates for other source categories. These efforts have yielded a new nationwide emissions inventory of the 10 priority substances. Although the highest of the utility emissions (shown in Table 1) are for hydrogen chloride, recent assessments indicate that hydrogen chloride emissions from individual coal combustion sources are not likely to pose a human health risk. EPRI researchers found that the new emissions estimates for the 10 trace substances were lower than previous estimates, both for utility emissions and for all sources combined. However, some nonutility sources remain poorly quantified, making estimates of the relative contributions of various source categories difficult.

Figure 1 A specialized flux chamber is used to take mercury measurements at an air-lake interface. This new tool is helping improve our understanding of the movement of mercury to and from surfaces. Measurements over soils, grasslands, and lakes are showing that under some conditions the net movement of mercury is from the surface to the atmosphere. Lakes in particular may be very active reemission zones during the summer.

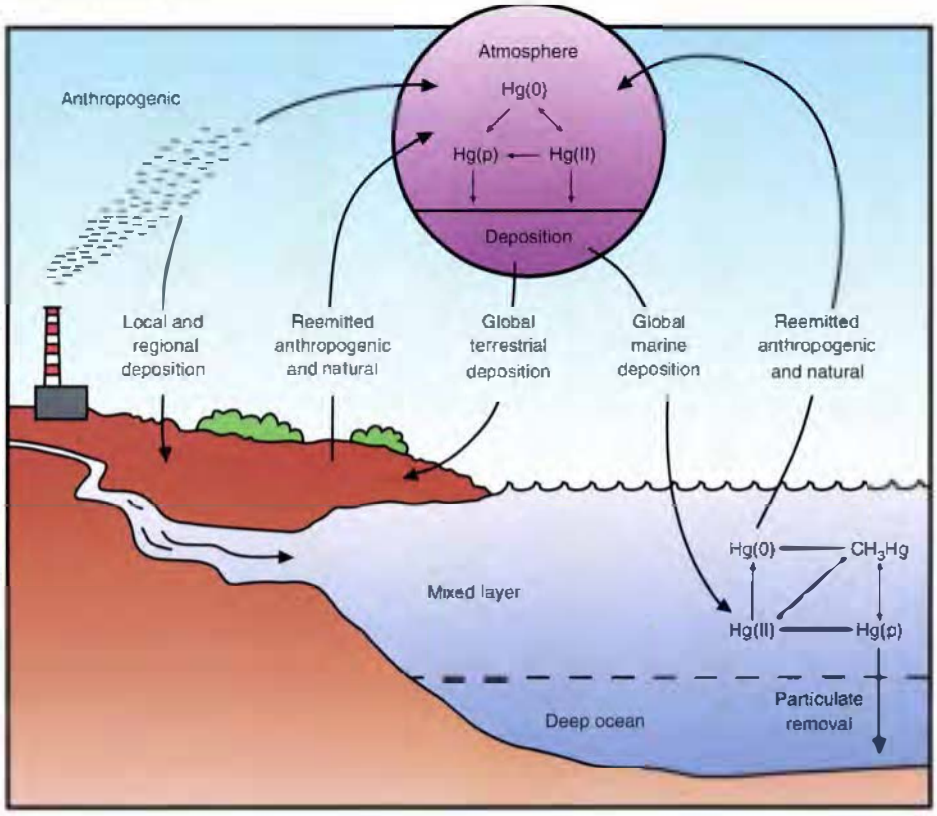
Form is important

The physical and chemical forms of emitted trace substances must be known to determine how they will affect the ecosystem—and where. Knowing whether a substance is present in a particulate or gaseous form is essential in designing effective control equipment and strategies. Once in the atmosphere, substances react and deposit on surfaces at greatly varying rates, depending on their form. This is especially important for mercury, which can be emitted as either gaseous elemental mercury, Hg(0), or gaseous or particulate divalent mercury, Hg(II). The distance that mercury travels in the atmosphere is largely dependent on its form: Hg(0) tends to remain suspended and to enter the global cycle, while Hg(II) is likely to be transformed and to deposit locally or regionally.

As part of the PISCES research, Nicholas Bloom of Frontier Geosciences has pioneered new methods of measuring the specific mercury species emitted from power plant stacks (methods that have applicability to ambient air measurements as well). The mercury-sampling system consists of a series of heated, solid-phase adsorbent traps for capturing mercury in the gas stream; subsequent laboratory analyses are performed by using cold-vapor atomic fluorescence spectroscopy. This advanced technique (called MESA, for mercury solid adsorption) allows investigators to discriminate between Hg(0) and the various oxidized species of mercury. Accurate measurements can now be made at the parts-per-billion and lower levels typical of stack and ambient conditions.

EPRI-developed sampling and analysis methods have already yielded new insights into how Hg(0) is converted into water-soluble compounds in the air—for example, labile inorganic Hg(II) and methylmercury (CH_3Hg). These chemical transformations appear to explain the high concentrations observed in precipitation measurements. This finding has underscored the need to include cloud-water mechanisms in mercury source-receptor models. EPRI researchers have explored this class of reactions under controlled conditions in a laboratory microchamber to develop the rate constants needed to drive analytical models. Work is continuing, with the emphasis shifting to reactions with particles in the atmosphere and follow-up research to confirm that gas-phase reactions are not generally significant.

Figure 2 EPRI has sponsored the development of a model, G-MCM, for studying the global mercury cycle. The model accounts for the atmospheric transport and transformation of mercury emissions and the cycling of mercury across the atmosphere-surface interface. It covers mercury in various forms—gaseous elemental, Hg(0); gaseous divalent, Hg(II); particulate, Hg(p); and methylmercury, CH_3Hg. Modeling results have indicated the importance of the reemission into the atmosphere of mercury that was emitted by anthropogenic and natural sources in the past and deposited on land surfaces and oceans.



Nature adds a twist

Because of the relatively low levels at which trace substances exist in the environment, it is not enough to know how air emissions from human activities are deposited. It is also necessary to understand how they are exchanged with the natural environment in forests, soils, lakes, and oceans. Building realistic models that relate trace substance emissions to environmental consequences requires a foundation of detailed observational data. EPRI's measurement efforts have concentrated on mercury, with investigators having to devise sensitive new techniques for detecting very low levels of mercury and accurately differentiating between its chemical forms. Mercury can be both deposited on and emitted from surfaces. The current understanding is that mercury is recycled through the atmosphere-surface interface many times before it reaches a sink in the biosphere (e.g., sediments).

To better understand that process, EPRI is sponsoring the MASE (Mercury Atmosphere-Surface Exchange in Forests and Lakes) project, being carried out by the Oak Ridge National Laboratory. The MASE investigators have devised a specialized flux chamber that permits field measurements of mercury at the atmosphere-surface boundary (Figure 1). Preliminary results have demonstrated that reemitted mercury is an important component of mercury cycling.

Building a better model

With an improved understanding of how trace substances are emitted, are transformed in the atmosphere, and cycle across the air-surface interface, the foundation has been laid for creating predictive mod-

els that relate power plant emissions to human and environmental exposure and ultimately to health risk. EPRI has assembled a multidisciplinary team to address this substantial technical challenge. Investigators at ENSR Consulting and Engineering and at Tetra Tech have developed state-of-the-science models to simulate the fate of power plant trace substance emissions on the local, regional, and global scales. Although still undergoing evaluation, these models have already proved useful for some initial investigations. Sensitivity analyses have been used to identify key components of the chemical transformation mechanisms and to assess whether any significant uncertainties or data gaps exist in our knowledge.

It is possible to explore the local impact of an individual power plant's mercury emissions by using the reactive plume model ENSR has developed. In simulating the power plant emissions of an EPRI member utility, the model estimated that about 1.5% of the mercury emitted from the power plant was deposited within 100 kilometers of the plant under clear sky conditions. During a rain event, however, deposition might increase to about 35%. Overall, annual local deposition was estimated to be less than 3%.

Analysis of ambient measurements indicates that for most areas much of the atmospheric and deposited mercury originates from sources throughout a broad region and from global background sources. To simulate regional processes, ENSR has developed the TEAM (Trace Elements Analysis and Modeling) system. TEAM is a three-dimensional Eulerian model that simulates the transport, dispersion, transformation, and deposition of the 10 priority trace substances. The model has already been used to estimate mercury emissions and occurrences for its entire North American domain. It is currently being used with MCM, a lake mercury cycling model, to study the distribution of mercury concentrations in fish at four sites in the United States.

To help both science and policy analysts better understand mercury on a global scale, EPRI has sponsored the development of the Global Mercury Cycling Model, or G-MCM (Figure 2). Developed by Tetra Tech, this mechanistic model can be used to analyze modern mercury budgets and to investigate historical changes in mercury deposition. Recognizing that the uncertainties in all global mercury budgets are very great, the model provides a framework for testing assumptions and incorporating new data as they become available. It has been calibrated by using historical records from sediments in lakes and bogs and recent estimates of global mercury fluxes.

Results from the model suggest that present-day anthropogenic emissions account for about 40% of the total mercury in the atmosphere, and that an additional 20% results from past anthropogenic emissions that are reemitted from oceans and land surfaces. G-MCM has shown the need to account for historical emissions from previous metal extractions in the Americas in order to approximate present-day atmospheric concentrations. The modeling also suggests that because of mixing, the ocean interior is a significant sink for mercury—a hypothesis that may explain why anthropogenic emissions have not raised ocean surface and atmospheric concentrations of mercury as high as some researchers had calculated. Such modeling results are helping to limit uncertainty in the background concentrations used for regional source attribution studies.

Putting it all together

To date, EPRI's air toxics research has established an initial basis for policy analysis. The EPA has drawn on this information in formulating its report to Congress. Research is continuing, guided by the results of initial risk assessments. Sensitivity studies have identified parameters for which existing uncertainty makes a large difference in the computed risk from trace substance emissions. Most of the big uncertainties lie in the areas of atmospheric sciences and environmental cycling and effects. Future research will focus on quantifying emissions sources, especially natural and background mercury sources. Identifying and modeling important transformation processes, and ultimately improving the reliability of our hierarchy of models.

New Contracts

Project	Funding / Duration	Contractor / EPRI Project Manager
Customer Systems		
Improved Fans for Heat Pumps (WO2892-24)	$77,400 10 months	Lemont Aircraft Corp. / *T. Statt*
Ground-Source Heat Pump Contingency Planning and Loop Costing Guides (WO3024-32)	$103,800 10 months	Dr. Andrew Lowenstein / *C. Hiller*
Study of Oil Field Motors and Other Application Opportunities for Written-Pole Technology (WO3087-30)	$86,000 11 months	Power Quality and Electrical Systems / *B. Banerjee*
Design and Testing of Doubly Salient Permanent-Magnet Machines (WO3087-31)	$175,700 9 months	University of Wisconsin, Madison / *B. Banerjee*
ProForma Software Tool (WO3121-14)	$67,700 8 months	Science Applications International Corp. / *P. Sioshansi*
Information Technology Needs of Utility Commercial Customers (WO3138-15)	$100,000 8 months	Utility Consulting Service / *S. Kondepudi*
Performance Measurement for Utility Programs and Services (WO3268-34)	$56,000 10 months	Hagler Bailly Consulting / *R. Gillman*
Market Opportunities in Electric Residential Cooking (WO3417-7)	$97,600 6 months	Quality Directions / *W. Krill*
Electrotechnologies in Multifamily Housing: Resource and Marketing Guide (WO3512-24)	$61,500 5 months	EDS Management Consulting Services / *S. Kondepudi*
Innovative Control Strategies for Supermarkets (WO3526-11)	$56,000 10 months	Encore Controls / *M. Khattar*
Environment		
Risk Ranking Methodology (WO2955-12)	$50,000 5 months	Carnegie Mellon University / *G. Hester*
Use of Constructed Wetland Treatment Systems for Removing Toxic Trace Elements From Utility Wastewaters: Role of Vegetation (WO4163-1)	$623,400 36 months	University of California, Berkeley / *J. Goodrich-Mahoney*
Subsurface Fate and Transport of Cyanide at Manufactured Gas Plant Sites (WO4193-1)	$250,000 29 months	Carnegie Mellon University / *I. Murarka*
Forest Response to CO_2 (WO9110-2)	$95,000 31 months	Desert Research Institute / *L. Pitelka*
Biosparging/Bioventing for Groundwater Management at a Manufactured Gas Plant Site (WO9115-1)	$225,700 30 months	Remediation Technologies / *I. Murarka*
Using Trees as Caps for Ash Pond Closures: Prototype Study (WO9121-1)	$150,000 3 months	Union Electric Co. / *I. Murarka*
Using Trees as Caps for Ash Pond Closures: Pilot Evaluation (WO9121-2)	$198,800 20 months	CH2M Hill / *I. Murarka*
Generation		
Measurement Errors in Heat Rate and SO_2 and CO_2 Emissions (WO2504-16)	$139,700 11 months	RMB Consulting and Research / *C. Dene*
APECS: Advisory Plant and Environmental Control System (WO2923-14)	$380,600 12 months	Praxis Engineers / *J. Weiss*
Thermal Performance Advisor for Gas Turbine Power Plants (WO3117-7)	$159,600 55 months	Enter Software / *G. Quentin*
Fossil Asset Management Case Study: Advanced Fuel Information System Specifications (WO3611-6)	$68,000 7 months	Resource Dynamics Corp. / *J. Platt*
GNOCIS Development (WO3715-3)	$50,000 16 months	Southern Company Services / *J. Stallings*

Project	Funding / Duration	Contractor / EPRI Project Manager
Nuclear Power		
Permanent Shielding Pilot Project (WO2967-5)	$150,000 7 months	Sargent & Lundy / *H. Tang*
COPO II: Corium Pool Experiments (WO3130-5)	$100,000 8 months	IVO International / *M. Merilo*
Evaluation of Alternative Filter Elements for Condensate Polishing Applications (WO3388-13)	$245,000 11 months	Duke Power Co. / *P. Millett*
Preventive-Maintenance-Basis Database and Reliability-Centered-Maintenance Support (WO4109-1)	$299,500 12 months	J. A. Jones Applied Research Co. / *J. Gisclon*
Methodology for Assessing the Level of Detail Necessary for Optimizing Plant Procedures (WO4171-1)	$135,000 8 months	Anacapa Sciences / *L. Hanes*
PWR Steam Generator Crevice Concentration Processes (WOS416-13)	$78,300 24 months	San Jose State University Foundation / *P. Millett*
Electrochemistry and Chemistry in a Heated Crevice (WOS522-6)	$175,800 12 months	Rockwell International Corp. / *P. Millett*
Corrosion Potential Measurements and Modeling of Simulated PWR Steam Generator Secondary Environments (WOS522-7)	$375,900 24 months	Pennsylvania State University / *P. Millett*
Leak Rate Measurements for Outside Diameter SCC Indications Restricted From Burst (WOS550-16)	$639,900 10 months	Westinghouse Electric Corp. / *D. Steininger*
Database Maintenance for Outside Diameter SCC at Tube Support Plate Intersections (WOS550-17)	$158,600 19 months	Westinghouse Electric Corp. / *R. Thomas*
Power Delivery		
Transmission Line Security-Level Assessment (WO2916-7)	$399,000 12 months	J. A. Jones Power Delivery / *P. Lyons*
Trace Transfer Capability Evaluation Code Enhancements (WO3140-6)	$720,000 18 months	ABB Systems Control / *A. Vojdani*
Reliability-Centered Maintenance for Transmission Lines (WO3621-2)	$75,000 7 months	J. A. Jones Power Delivery / *P. Lyons*
Inspection/Detection of Defects in In-Service Components (WO3621-3)	$305,000 19 months	J. A. Jones Power Delivery / *P. Lyons*
Development of Advanced Artificial Neural Net Short-Term Load Forecaster (WO3692-3)	$218,700 23 months	Pattern Recognition Technologies / *D. Maratukulam*
Live Working 2000 (WO3787-8)	$254,500 12 months	J. A. Jones Power Delivery / *P. Lyons*
Strategic Development		
Technical Potential for Electrification (WO8023-1)	$66,300 4 months	Regional Economic Research / *T. Henneberger*
Nonlinear Dynamics of Rotating Systems (WO8033-1)	$75,000 19 months	University of Illinois, Urbana / *T. McCloskey*
Heat Loss Through and Formation and Stability of a Solid Layer During Solidification (WO8034-12)	$235,900 31 months	University of Wisconsin, Madison / *M. Merilo*
Multilayer Thermal Barrier Coatings for Gas Turbines: Diffusion Bond Coatings (WO8042-8)	$238,300 36 months	Ohio State University Research Foundation / *W. Bakker*
Electrochemical Formation and Luminescence of Porous Silicon (WO8060-15)	$307,200 36 months	University of Rochester / *F. Will*

EPRI Events

DECEMBER

11–12
Transmission Line Grounding Workshop
Location to be announced
Contact: Mike McCafferty, (817) 439-5900

12–14
North American Electric Vehicle and Infrastructure Conference
Atlanta, Georgia
Contact: Lori Adams, (415) 855-8763

JANUARY 1996

8–12
Power Systems Analysis Using the Electromagnetic Transients Program for Windows
San Francisco, California
Contact: Bill Long, (608) 262-1199

FEBRUARY

5–7
Substation Equipment Diagnostics Conference IV
New Orleans, Louisiana
Contact: Denise Wesalainen, (415) 855-2259

5–8
Hydrogenerator Maintenance
New Orleans, Louisiana
Contact: Denise Wesalainen, (415) 855-2259

7–9
Municipal Water and Wastewater Conference
New Orleans, Louisiana
Contact: Kim Shilling, (314) 935-8590

13–16
Healthcare Initiative Conference
Los Angeles, California
Contact: Janis Pritti, (415) 641-8332

20–21
Center for Materials Production Workshop on Industrial Minerals
Ontario, California
Contact: Joe Goodwill, (412) 268-3435

20–22
Turbine Generator Operations and Maintenance
Redondo Beach, California
Contact: Denise Wesalainen, (415) 855-2259

29–March 1
1996 Power Delivery Issues Meeting
Location to be announced
Contact: Jon Ferguson, (817) 439-5900

MARCH

7–8
EPRI Partnership for Industrial Competitiveness
Chattanooga, Tennessee
Contact: Bill Smith, (415) 855-2415

11–15
Steam Turbine Blade Life Evaluation
Rochester, New York
Contact: Jeannie Blanchard, (716) 424-2010

12–14
Disaster Preparedness
New York, New York
Contact: Susan Bisetti, (415) 855-7919

19–20
Managing for Biodiversity: Emerging Ideas for the Electric Utility Industry
Williamsburg, Virginia
Contact: Christine Lillie, (415) 855-2010

27–29
Innovative Approaches to Electricity Pricing: Managing the Transition to Market-Based Pricing
San Diego, California
Contact: Lori Adams, (415) 855-8763

APRIL

8–11
1996 International Fossil Simulation and Training Meeting
New Orleans, Louisiana
Contact: Ron Griebenow, (816) 235-5622

9–11
The Future of Power Delivery
Washington, D.C.
Contact: Christine Lillie, (415) 855-2010

9–11
1996 Electric Food Service Symposium
Nashville, Tennessee
Contact: Susan Bisetti, (415) 855-7919

10–12
Pollution Prevention Seminar
Denver, Colorado
Contact: Linda Nelson, (415) 855-2127

MAY

8–10
CEM (Continuous Emissions Monitoring) Users Group Meeting
Kansas City, Missouri
Contact: Linda Nelson, (415) 855-2127

22–24
1996 Heat Rate Improvement Conference
Dallas, Texas
Contact: Susan Bisetti, (415) 855-7919

JUNE

3–4
Motor Rewind Course
Atlanta, Georgia
Contact: Denise Wesalainen, (415) 855-2259

4–5
Repowering Conference
Washington, D.C.
Contact: Christine Lillie, (415) 855-2010

4–6
EPRI Reactor Pressure Vessel Inspection Conference
Squaw Valley, California
Contact: Susan Otto, (704) 547-6072

10–13
Balance-of-Plant Heat Exchanger Workshop
Jackson Hole, Wyoming
Contact: Kenji Krzywosz, (704) 547-6096

11–13
Interaction of Non-Iron-Based Materials With Water and Steam
Piacenza, Italy
Contact: Linda Nelson, (415) 855-2127

17–19
6th International ISA POWID/EPRI Controls and Instrumentation Conference
Baltimore, Maryland
Contact: Lori Adams, (415) 855-8763

JULY

22–24
1996 International Low-Level-Waste Conference
New Orleans, Louisiana
Contact: Linda Nelson, (415) 855-2127

24–26
ASME/EPRI Radwaste Workshop
New Orleans, Louisiana
Contact: Linda Nelson, (415) 855-2127

29–August 1
Fossil Plant Maintenance Conference
Baltimore, Maryland
Contact: Lori Adams, (415) 855-8763

AUGUST

7–9
International Conference on Sustainable Thermal Energy Storage
Chicago, Illinois
Contact: Beverly Speer, (608) 262-8220

26–30
Condenser Technology Seminar and Conference
Boston, Massachusetts
Contact: Lori Adams, (415) 855-8763

OCTOBER

7–10
Hydrogenerator Maintenance
Seattle, Washington
Contact: Denise Wesalainen, (415) 855-2259

NOVEMBER

13–15
Solid-Particle Erosion
Nashville, Tennessee
Contact: Linda Nelson, (415) 855-2127

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