Quality of Power

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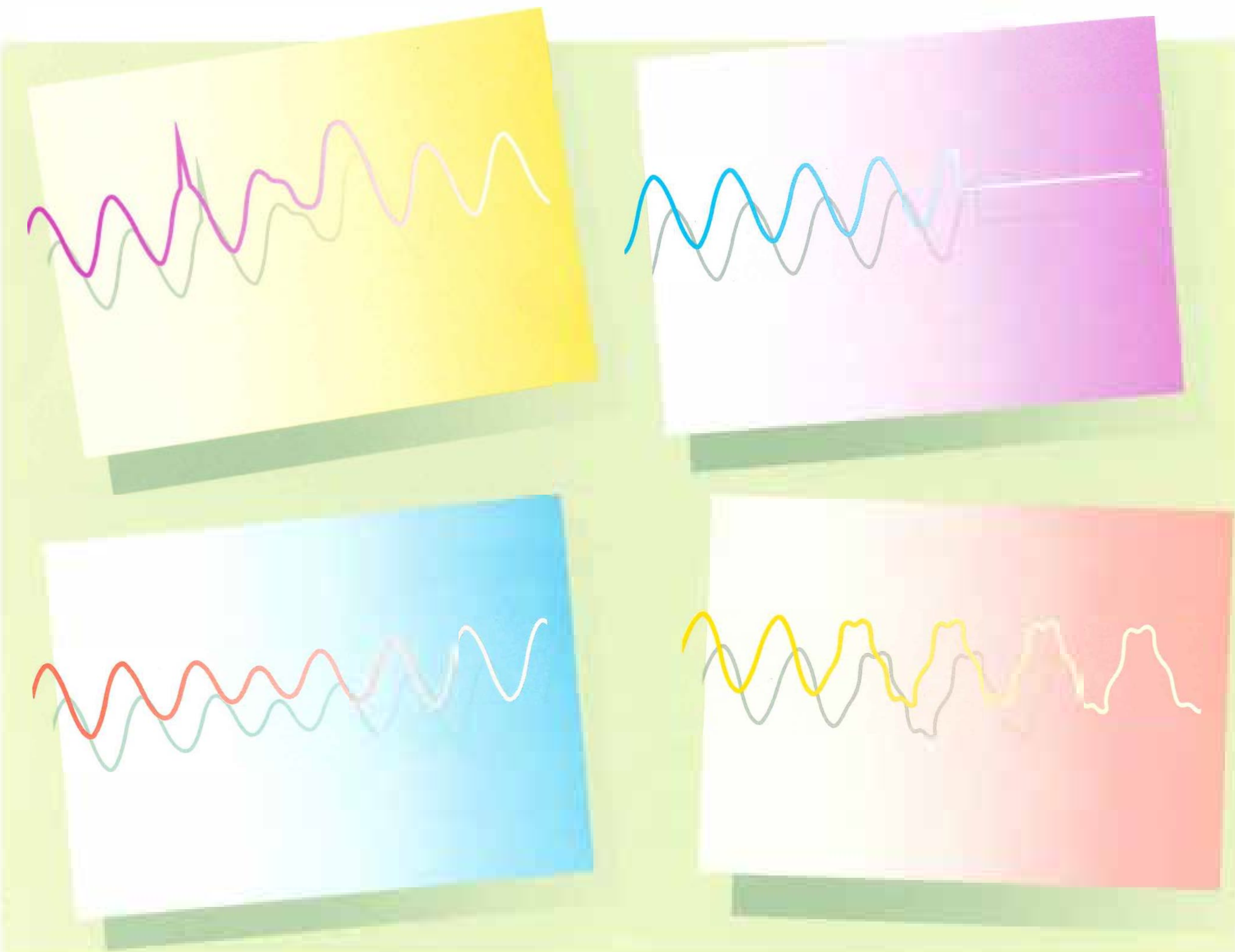

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EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution, and utilization.

Address correspondence to:
Editor in Chief
EPRI JOURNAL
Electric Power Research Institute
P.O. Box 10412
Palo Alto, California 94303

Cover: Concern over power line disturbances is growing as electronics permeate society. Four major types of disturbances are surges, sags, outages, and harmonic distortions.

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Utilities and Power Line Distortion

Since the earliest days of electric power, customers have counted on utilities to provide electricity that is as free as possible from outages, voltage surges, and the current waveshape distortions known as harmonics. Reducing such power line disturbances has always been a critical concern for utilities, which currently spend more than a billion dollars annually in their efforts to maintain the quality of electric power. Recently, however, new sources of disturbance have begun to proliferate, just as many pieces of customer equipment are becoming more sensitive to power irregularities. These developments have presented utilities with a new set of complex issues related to the quality of power that will require wide-reaching cooperative efforts to resolve.

This month's *Journal* cover story discusses some of the technical and economic challenges utilities face as they try to provide high-quality electric power to their customers under increasingly difficult circumstances. Some electrical disturbances, such as outages caused by storms that blow down power lines, have long been recognized as being beyond a utility's ability to eliminate completely. Similarly, utilities are now finding that they cannot always remove power distortions caused by one customer's equipment and prevent those distortions from affecting other customers along a line.

Harmonic currents caused by many types of customer load and utility equipment provide a good case in point. For many years, such irregular currents originated mainly from a few major sources, such as arc furnaces and HVDC terminals. In these cases, they could be removed with relative ease by placing a large (and expensive) filter between the source and the main power line. Today, however, significant power line harmonics are being caused by many small, widely dispersed customer loads, such as rectifiers and the solid-state controls for variable-speed motors. At the same time, an increasing number of other customers are using sensitive equipment, such as computers, the operation of which may be adversely affected by harmonics.

It would not be economically feasible for utilities to detect and filter each small source of harmonics or to isolate each sensitive load from all power line disturbances. A more reasonable approach involves control of harmonics through filters installed on the offending loads and protection of sensitive electronic apparatus through special power-conditioning equipment. Such an approach will obviously require collaboration among utilities, equipment manufacturers, regulatory agencies, and standards-setting bodies.

This effort has already begun. Some utilities are already working directly with their customers to analyze and solve specific power quality problems. Professional engineering societies are considering new standards to limit the amount of harmonic currents specific pieces of equipment produce. And several types of protective power supplies are now commercially available for use with computers. Still missing, however, are critical data on specific kinds of electrical disturbances, including their various sources, the severity of their effects, and the effectiveness of proposed mitigation schemes.

EPRI is now sponsoring research that can help provide some of this missing information. One EPRI project, for example, has already produced a computer code that utilities can use to model the propagation of harmonics along power lines, and another project is under way that will quantify the effects of harmonics on sensitive electronic equipment. Through these and other research efforts, utilities will be armed with new ways to analyze and reduce power line disturbances and thus to ensure the highest possible quality of power for their customers.

John J. Dougherty, Vice President
Electrical Systems Division

Authors and Articles

When a TV picture is fuzzy, we easily understand that its signal is subject to unpredictable interference out in the ether. But when a computer burps, we demand an immediate cure for any perturbation of its hard-wired electric power. Actually, it's not all that simple, according to John Douglas, the science writer whose article **Quality of Power in the Electronics Age** (page 6) is featured in this issue. New electric and electronic devices on both sides of the meter may create pervasive disturbances on a utility system. Douglas conferred with several EPRI staff members as he drew information together for the article, but his principal resource was James Mitsche of the Electrical Systems Division.

Mitsche, an EPRI project manager since June 1980, specializes in computer modeling and analyses for the Power System Planning and Operations Program. He was previously on the engineering staff of Consumers Power Co. for three years.

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Power plant heat rate, availability, and stack emissions are important to utilities, and upping fuel quality is one way to improve them. That's why coal-cleaning technology is getting a better reputation among utilities today. **New Perspective on Coal Cleaning** (page 14), by feature writer Michael Shepard, positions EPRI's current R&D among the various options for better power plant operating economy. Shepard's resources included EPRI's contractors at its Coal Cleaning Test Facility (CCTF) in Homer City, Pennsylvania, as well as four staff members in the Coal Combustion Systems Division.

Clark Harrison has been EPRI's project manager for CCTF since May 1982. Before that he was in R&D marketing with Babcock & Wilcox Co. for two years, and still earlier, he was with Pennsylvania Power & Light Co. for seven years. Harrison's utility work included environmental and licensing studies and fuel supply planning.

James Hervol is also a project manager at CCTF, much of his work involving coordination with other agencies on what are called affiliated projects. Before he came to EPRI in August 1982, Hervol worked for two years with Skelly and Loy, mining consultants, and for three years prior to that, with the eastern regional engineering office of Consolidation Coal Co.

Frederick Karlson heads EPRI's Fuel Quality Program, which includes CCTF research. He joined EPRI in January 1981 after 16 years with the Bechtel organization, the last 5 years as a project engineer for Bechtel Civil & Minerals, Inc., where he worked on a DOE-funded evaluation of coal mining and coal conversion technologies.

Michael Miller, an environmental analyst and planner, is technical manager for environmental assessment in the Coal Combustion Systems Division. Before coming to the EPRI staff in March 1980, he worked for two years with Pacific Gas and Electric Co., successively in the environmental quality department and the planning and research group. Before that he conducted air quality studies for URS Corp.

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Corrosion control in the blading of a steam turbine traditionally has been achieved by walking a narrow path of adjustments to operating conditions and steam chemistry. But avoiding the problem by using more-corrosion-resistant materials should be a less-complicated solution. And it is now close at hand, as described in **The Titanium Solution to Turbine Blade Reliability** (page 22). Written by Taylor Moore, senior feature writer, the article recounts eight years of EPRI-sponsored R&D to qualify a titanium blade design for utility use. Research managers from two EPRI groups contributed their expertise to the article.

Robert Jaffee has been with EPRI since July 1975, successively as manager and senior technical adviser to the Institute's Materials Support unit. He began his EPRI work in 1974 while on leave from the Columbus Laboratories of Battelle Memorial Institute, his employer for 32 years. Jaffee eventually became chief materials scientist there, as well as "Mr. Titanium" in the U.S. metallurgy community.

Thomas McCloskey has been with EPRI's Coal Combustion Systems Division since December 1980, specializing in research to improve the performance and reliability of steam turbines. He formerly worked for 11 years in the steam turbine division of Westinghouse Electric Corp.

John Parkes manages the Availability and Life Extension Program in the Coal Combustion Systems Division. He joined EPRI in April 1977 and at that time worked mostly in steam turbine reliability. Parkes's principal earlier experience was with General Electric Co., where he worked for six years in steam turbine development and design.

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When electrical load is growing, say, at a steady 5% annually, utilities have a clearcut requirement to step up system capacity in all respects. But when load growth is slow and irregular, it is difficult to devise the smaller, selective steps that are both adequate and economic. **Transmission Line Uprating: Strategic Option for System Planners** (page 32) reviews a number of computer-aided solutions in overhead line design that have come from R&D and should prove practical in uncertain times. David Salisbury, science writer, developed the article; his principal research source was EPRI's Richard Kennon.

Kennon has managed the Overhead Transmission Lines Program of EPRI's Electrical Systems Division since 1978. A project manager before that, he joined the Institute in February 1975 after nearly 23 years with Westinghouse Electric Corp. Working first as a sales engineer, Kennon later turned to design and became manager of Westinghouse capacitor engineering in 1970.


Kennon


Karlson


Mitsche


McCloskey


Parkes


Jaffee


Miller


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QUALITY OF POW
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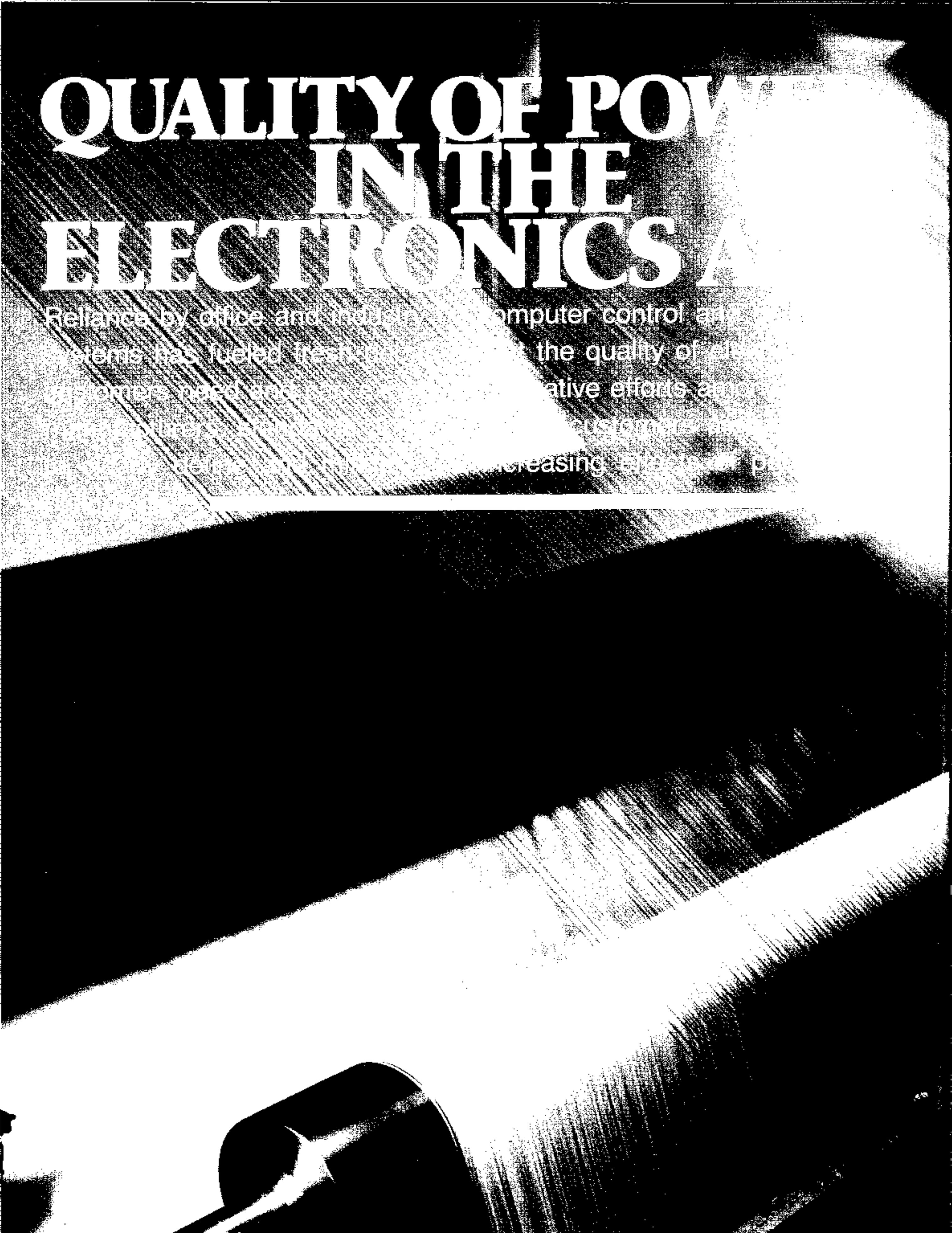


The recent proliferation of sophisticated electronic equipment has rejuvenated an old problem for electric utilities—customer concerns about the quality of power they receive. To provide reliable service, electric power has to meet certain standards for voltage levels, continuity, and amount of waveshape distortion. Some pieces of electronic equipment are particularly sensitive to deviations from these standards; others can actually cause distortions. Computer memories, for example, can be lost if voltage is too low for even a few milliseconds. On the other hand, even small electronic power converters (such as dimmer switches for household lights or controls for variable speed motors) can distort waveshape and cause problems elsewhere on a power line.

In some instances the problem has become acute. One utility, for example, recently received complaints from an electronics manufacturer that its production was impaired because of power disturbances that were eventually traced to an arc furnace elsewhere on the utility's line. Another utility is offering on-site backup power supplies for a set monthly fee to customers who demand uninterruptible service. Still other utilities have established full-service operations to help customers analyze and solve power quality problems. Meanwhile, the number and scope of complaints about the quality of power continue to mount as customers report problems with applications that range from office computers and automated industrial processes to hospital life support systems.

Because both the causes and consequences of power quality problems are so diverse, they are not likely to be amenable to a single solution. There is no quick technologic fix. Rather, a broad spectrum of cooperative efforts among utilities, electronic products manufacturers, organizations that produce standards, and individual customers will probably be needed to identify the various technical issues, conduct research, establish standards, and implement solutions. A variety of such efforts are already under way, including some involving EPRI. Whether further coordination of these initiatives is needed and what role EPRI might play in providing such coordination have not yet been determined.

Some lessons from history

The need to provide power with a steady voltage and frequency has been recognized since the inception of the electric utility industry. As public expectations of uniform lighting intensity grew and as more manufacturers began to use electric motors to drive their production lines, utilities adopted increasingly strict standards for voltage regulation. During the 1930s utilities also found that they had to pay increasing attention to voltage disturbances on their distribution lines caused by customer equipment. Research at the time showed that visible flicker in incandescent lamps caused by voltage fluctuations in the range between 6 and 12 Hz was particularly annoying, and that it could be perceived by many people even if the pulsation on an incoming line was only a third of a volt on a 120-V system. This type of problem led to an increasing number of industry standards on end-use equipment to reduce voltage fluctuations sent back along a power line.

A somewhat different problem arose during the 1950s as air conditioners rapidly became popular. When early models were switched on, so much energy was used to get their compressors started that the incoming line voltage was temporarily reduced and the motors often could not reach operating speed, ran poorly, or stalled. Fortunately, in this case, a technologic fix was readily available. The alternating current flowing through an electrical device can either lead or lag the alternating voltage driving it. In a motor the current tends to lag the voltage because of the time required to charge the magnetic field in the motor's coils. This deviation can be corrected simply by adding a capacitor to the circuit, which produces a leading current. After utilities and air conditioner manufacturers agreed on standards for the use of such capacitors, coupled with changes in the distribution system, the problem of nonstarting or poorly running motors declined.

The reason why today's complaints about the quality of power cannot be handled so simply is that they seem to reflect both a multitude of different causes and a variety of specific sensitivities in the customer equipment most affected. Just as the air conditioner problems were eventually solved by a coordinated effort among affected parties, so too can new standards on equipment and on levels of permissible voltage distortions help guide the design and application of both sensitive electronic equipment and heavy-duty apparatus. Such standards will have to be applied much more selectively than in the past, however, and address a much more complex set of issues.

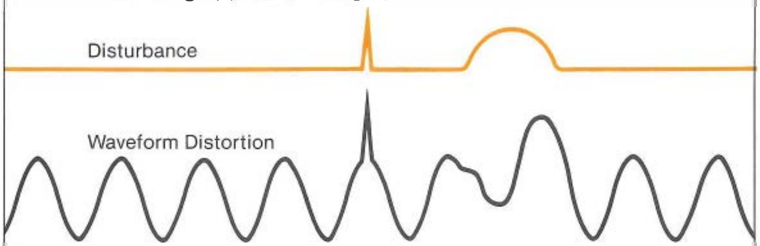
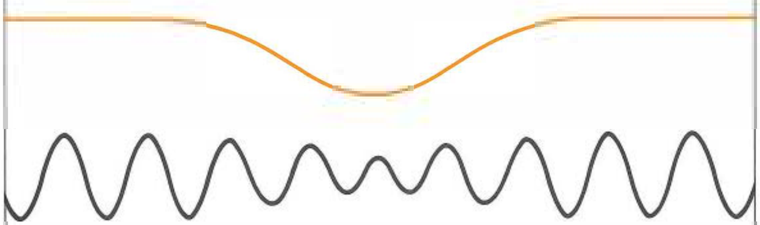
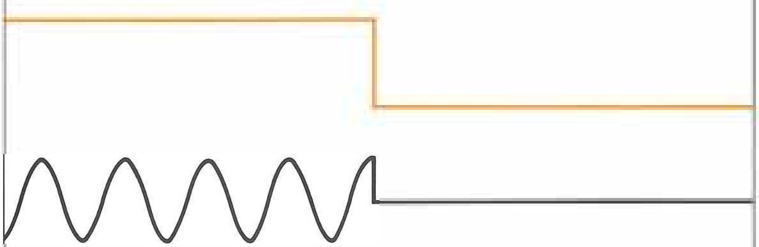
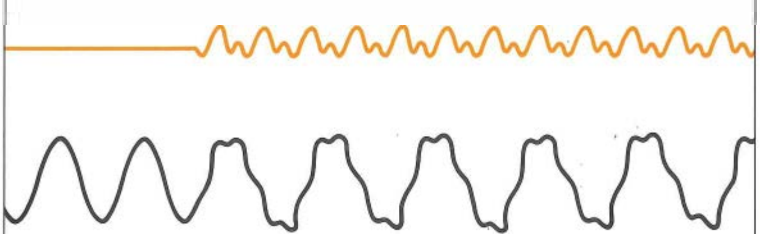
Types of disturbance

Power line disturbances are usually classified by their duration, although neither the terminology nor the demarcation lines of such classification have yet been standardized. The four types that are now receiving most attention are surges (very short overvoltages), dips (somewhat longer undervoltages), outages, and waveshape distortions.

The most easily corrected type of voltage problems on a power line are surges, or spikes, that typically last only fractions of a millisecond. Surges may be caused by lightning striking a utility line, by switching operations, or by operation of various loads on a line. If they reach too high a peak, surges can damage computers and most other electronic equipment, but such extreme spikes are rare. Moreover, inexpensive

Describing Disturbances

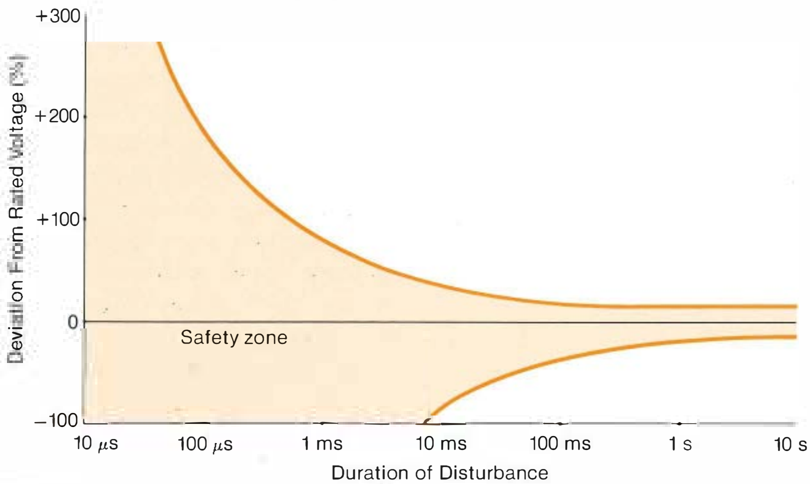
Power generated by a utility has a regular sinusoidal shape, but disturbances and electrical devices on a power line can distort this signal enough to interfere with customer equipment. Such disturbances are generally classified by how long they last: they range from sudden voltage spikes caused by lightning to extended outages resulting from broken power lines. In addition, harmonic distortion appears as higherfrequency signals imposed on the basic 60-cycle line current.

	Causes	Duration
Overvoltage (spikes and surges) 	• Lightning • Power network switching • Operation of on-site customer loads	Spikes: from 0.5 to 200 μs Surges: up to 16.7 ms
Undervoltage (sags) 	• On-site customer load changes • Faults on the power system • Large load changes in the utility service area • Utility equipment malfunction	From 67 ms to 1 s
Outage 	• Short circuits on the power system • Malfunction of utility equipment • Malfunction of on-site customer equipment	From 2 to 60 s if correction is automatic; unlimited if correction is manual
Harmonic distortion 	• Discontinuous or nonlinear electronic control devices • Saturated utility transformers	Unlimited

EPRI research being performed by SRI International is aimed at evaluating commercially available power line conditioners (PLCs) and uninterruptible power supplies (UPSs) on the basis of a number of technical parameters, including utility grid compatibility. One result of this work will be a PLC/UPS directory that will help users assess their protection requirements and match them with available equipment for specific end-use applications.

Surges, Sags, and Computers

Computers are more sensitive to over- and undervoltages than most other electrical equipment, with a potential loss of computer memory depending on both the duration and the severity of the disturbance. Studies by the U.S. Navy on large computers have established a zone of safety within which the computer is unlikely to sustain interruption or memory loss from voltage variations. For example, a computer could generally withstand a surge of 100% of its rated voltage for up to 1 ms.



surge arresters, which may cost only a few dollars for personal computers, can protect against severe overvoltages.

Computers are particularly susceptible to dips, undervoltages lasting half a cycle (8.33 ms) or longer. Such dips may cause digital electronic systems to lose memory if the voltage falls below about 87% of its rated value. Momentary dips usually result from power system faults (short circuits) that are automatically disconnected, from the startup of large loads, or from utility equipment malfunction. Solid-state line voltage regulators can protect computers and other sensitive equipment from some voltage dips, and motor generators can protect devices from most.

The most severe type of line disturbance is an outage, or severe undervoltage that lasts longer than two seconds. Severe weather conditions, such as high winds that blow tree branches onto power lines or lightning strikes that cannot be counteracted automatically, are the most frequent causes of such outages, followed by traffic or construction accidents involving utility poles. An uninterruptible power supply (UPS) is needed to fully protect a computer from crashing during an outage. Typically, such a UPS consists of batteries, dc-to-ac converters, and electronic switching equipment that provide enough power to enable an operator to save the information stored in a computer's memory and conduct an orderly shutdown. A UPS to protect a personal computer against outages costs several hundred dollars; one for a large mainframe may cost more than a hundred thousand dollars and may also require another several thousand dollars of maintenance and energy annually.

The last major type of disturbance is more complicated. Solid-state power-conditioning devices, such as rectifiers and the controls for variable speed motors, distort the current waveshape in a line. These distortions are equivalent to mixtures of many higher frequencies, called harmonics, each of which is a whole-number multiple of the ordinary 60-Hz frequency. Taken together, these harmonics produce current waveforms in a line that may resemble the jagged peaks of a mountain range more than the smooth, sinusoidal curve of the original 60-Hz current.

The effects of harmonic currents in a power line on the operation of various pieces of equipment are subtle and still have not been fully assessed. Computers, for example, appear to be relatively immune to some low-level harmonics, and their own internal power converters can send additional harmonic currents back into the utility source. An ongoing EPRI project being conducted by SRI International shows, however, that computers can malfunction when operated on the same circuit with harmonic-producing devices. One aim of the project is to determine a threshold in sensitive equipment for interference caused by harmonics.

Harmonics may also cause motors and transformers to heat up excessively by inducing eddy currents in the solid metal parts around which coils are wound. They can also create voltage stress in power capacitors because the insulation material inside heats up at higher frequencies. A 10% increase in voltage stress caused by harmonic currents typically results in a 7% increase in the operating temperature of a capacitor bank and can reduce its life expectancy to 30% of normal. Installing filters can prevent the propagation of harmonics along a power line, but that measure raises questions: Where should the filters be placed? Will they operate properly under a variety of system conditions? Who will bear the expense of their installation?

What utilities can do

From the customer's point of view, the most urgent issues related to the quality of power are how to prevent the loss of valuable computer data and the expense of shutting down process control manufacturing lines because of voltage dips and outages. Unfortunately, because many of the faults that cause them result from random events, such as storms and accidents, these types of line disturbances are the most difficult to combat and probably will never be eliminated completely. Utilities are already spending more than $1 billion each year to prevent power interruptions through projects that range from installing lines underground and setting power poles farther away from traffic to using a tree growth inhibitor on trees near power lines. In addition, separate transformers may be used for plants with sensitive loads so, for example, a computer manufacturer is not placed on the same feeder as an arc furnace. Beyond such measures, however, the main alternative available to the computer user is to purchase a UPS, which some utilities are now helping their customers lease or purchase.

The problem of what should be done to limit harmonics is more complex, but at least the solutions remain within the realm of technical feasibility. Utilities and their customers have every reason to cooperate in the search for such solutions because both parties have transformers, capacitors, and other equipment that are threatened by the overheating and voltage stress that harmonic currents can cause. The first step of this search, already undertaken as a part of R&D projects at EPRI and elsewhere, is to identify the major sources of power line harmonics and to determine just how much damage they are likely to cause.

One project that examined these issues was completed last year and found that the introduction of solid-state power conversion equipment has greatly increased the incidence and severity of harmonics on utility lines. The project's final report concluded: "Formerly the harmonic currents flowing on the power lines were the result of incidental or second-order effects, such as the operation of an overexcited transformer. Today, in contrast, we have power conversion equipment in which harmonics are a first-order effect, meaning that harmonic current flow is required for the operation of the equipment. In effect, the distortion problem that once was somewhat esoteric and anomalous now portends a significant contamination of the power distribution environment."

The report identified two very different types of sources of harmonic currents—large, easily identifiable pieces of industrial equipment, and small, widely dispersed household appliances. There were not enough data, however, to quantify the contribution each type of source made to harmonics on utility feeder lines or to estimate how serious the effects might be. The researchers noted that no agreement has yet been reached on determining the effect of harmonics-producing equipment and concluded that the importance of harmonics has not yet been widely enough recognized.

New standards and beyond

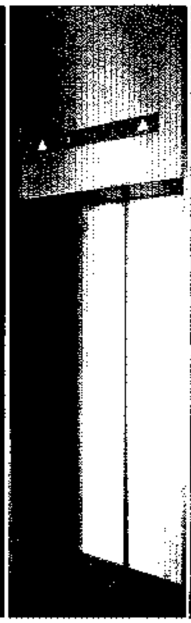
Once further data are collected, they will probably be used by organizations such as the American National Standards Institute (ANSI) and the Institute of Electrical and Electronics Engineers (IEEE) to set new standards governing the injection of harmonic currents onto utility lines. Standards committees of various professional societies are already considering the issue, and the engineers involved often point to Europe as a model of what may be expected. In particular, European nations have adopted a common standard that sets limits for each individual harmonic (up to the 40th order) that can be produced by a single domestic appliance with power electronics. For large industrial units, specific countermeasures must be coordinated by the utility and the customer.

"Utilities can handle this problem in the same way they treat equipment with poor power factors," says John Dougherty, EPRI vice president and

SOURCES OF DISTORTION


HVDC terminal


Electric arc furnace


Elevator


Variable-speed drill

Battery charger

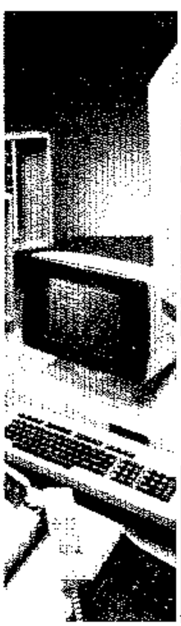
Microwave oven

Villains and Victims

Some types of customer load are likely to create harmonic distortion problems on a utility system, while other types generally suffer the consequences of these problems. Today's utilities are serving more of both types of load than ever before. HVDC terminals, variable-speed motors, and arc furnaces are among the perpetrators of power distortions, while devices such as computers, television sets, and sensitive industrial machinery are those most at risk.

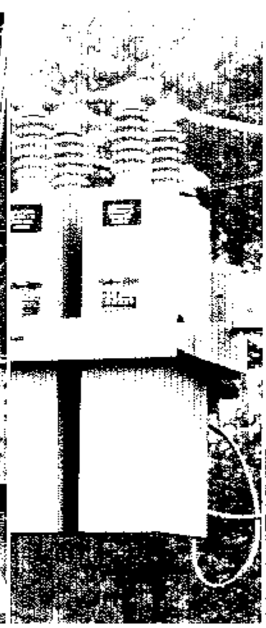
AFFECTED DEVICES

Computer



Computerized production line

Utility capacitors



Utility transformer

Television

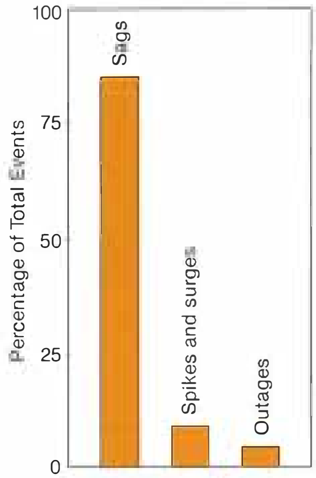
Audio equipment

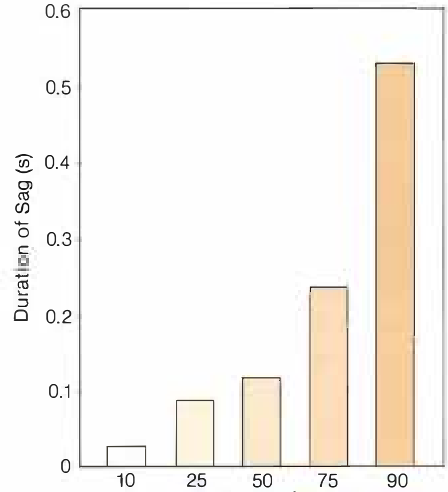
director of the Electrical Systems Division. "Either the harmonics from a major installation are removed by filters before they enter the utility line or the customer pays a rate penalty. Utilities should not be responsible for cleaning up disturbances caused by a customer's poorly designed equipment."

Although this approach would help reduce harmonics on utility distribution lines, further steps may have to be taken to protect equipment inside homes and offices. Here, the problem is harmonic currents and other disturbances caused in nearby wiring by light dimmers, personal computers, and other appliances. New standards on the European model would help, but manufacturers of sensitive equipment may also have to build more protective devices into their equipment. Computers, for example, are not affected by most spikes and harmonics, but built-in surge arresters and filters could protect them against the rare disturbances large enough to harm circuits or alter stored data.

Case Study on Power Quality

Although results may not be representative of large-sector problems, research performed by the Bell System on commercial ac power disturbances found that power sags were by far the most common disturbances at 24 Bell data-processing sites from 1977 to 1979. The study also found that 75% of these sags lasted a quarter of a second or less, and only about 10% lasted more than half a second.





Protection Devices

A variety of devices are available to protect sensitive equipment from the most common types of power disturbances. The least expensive of these are surge suppressors, which smooth out spikes and surges from incoming power. Power line conditioners both isolate electrical noise and regulate voltage (to handle surges and sags). Uninterruptible power supplies, which add protection against outages and harmonic distortion, offer the ultimate in protection; a 500-VA unit can be small enough to fit on a tabletop, while large commercial or industrial UPSs with dozens of backup batteries can fill entire rooms.

Power line conditioner

500-VA UPS

Surge suppressor

75-kVA UPS

UPS batteries

"A workshop on the issue of the quality of power, involving utilities and equipment manufacturers, could prove useful," comments Walter Esselman, director of Engineering Assessment and Analysis. "This is a mutual problem that all parties can contribute to solving. It would also provide an opportunity for EPRI to bring together technical experts with many different perspectives on the matter."

Frank Young, manager of Strategic Planning, sees a possible long-term role for EPRI in fostering a cooperative approach to addressing power quality concerns. "We can act as an information center, a clearinghouse of ideas on how to deal with power disturbances," he says. "Some utilities are already working closely with their customers by holding seminars on the quality of power and sometimes offer advice on specific problems. EPRI is in a good position to make other utilities aware of these initiatives."

One example of such a cooperative approach is a series of one-day seminars Northeast Utilities holds for its customers to discuss the effect of power line disturbances on computer operations. The seminars include presentations by specialists from the utility, computer companies, and power conditioning equipment manufacturers and cover such topics as diagnostic troubleshooting, evaluation of computer installations, the power requirements of computers, and the inherent limitations of power supply systems. The intent of these seminars, according to the literature provided participants, is to present an overview of the kinds of problems that affect different types of computers and to consider the cost and feasibility of various solutions.

Research for quality

In addition to whatever role EPRI may play in helping utilities work with manufacturers and customers to decrease the effects of power line disturbances, research into the problems themselves is being pursued in a variety of ways. One product of this ongoing research effort that utilities can use now is the computer code HARMFLO, which helps identify major sources of harmonic currents on a power grid and analyzes their propagation. The code has recently been used in Minnesota to assess the potential effects of a plasma arc heater and in Texas to locate sources of harmonics that interfered with air traffic control radar at a major airport. By using such codes, utilities will be better able to choose appropriate methods for reducing harmonic currents on their lines and to set interface standards for customer equipment.

Another project already under way at SRI International is designed to determine the effects of harmonics on power line carrier systems. Such systems involve the use of high-frequency signals sent along power lines to control or monitor various aspects of power transmission and distribution operations. One signal, for example, might be sent out by a device attached to a major circuit breaker indicating its status, and another might be sent from a system operator to the circuit breaker to switch it on or off. Stray harmonic currents of sufficiently high frequency and intensity can interfere with such signals and cause incorrect operation. The present project is assessing the scope of the problem.

To provide a guide to utilities that intend to site power converters on their systems, EPRI has published a study of distribution surge and harmonic characteristics (EL-1627). The study can help utility personnel identify critical locations in a distribution system where interference from such converters might cause a problem. In particular, this publication indicates what measurements, analysis, modeling, and planning tasks have to precede siting of a power converter.

EPRI has also provided utilities with new tools for protecting customers from the effects of lightning. A modified, fail-safe 10-kV surge arrester developed with EPRI funds is now commercially available. The prototype of a device that can locate faulty surge arresters without exposing utility personnel to hazard from high-voltage power lines is now undergoing field tests. And a new instrument to measure voltages and currents on distribution lines when they are hit by lightning is being refined; commercial availability is expected in late 1985.

Despite such efforts, complaints about the quality of power are likely to continue rising. Any new standards related to equipment performance or regulations limiting the injection of harmonics into a distribution system will have to be more selective and complex than similar measures adopted earlier to correct problems with air conditioners. Research will continue to reduce disturbances in power lines, but some outages will inevitably remain. Part of the task now facing the electric power industry will be to continue ongoing efforts to improve the quality of power, but another part will involve working with customers to mitigate the effects of problems inherent in the system.

Further reading

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This article was written by John Douglas, science writer. Technical background information was supplied primarily by James Mitsche, Electrical Systems Division. Additional information was provided by Richard Steiner, Robert Iveson, William Shula, Herb Songster and Harry Ng, Electrical Systems Division; Ralph Ferraro, Energy Management and Utilization Division; Frank Young, Planning and Evaluation Division; and Walter Esselman, Engineering Assessment and Analysis.

New Perspective on Coal Cleaning

Coal cleaning has advanced dramatically from the hand labor of turn-of-the-century cleaning crews. But in addition to technology improvements, utilities can now benefit from detailed characterizations of the cleanability of specific coals and from emerging techniques for measuring the effect of coal quality on plant performance.

Boney pickers, they were called in the nineteenth and early twentieth centuries—old or disabled miners and young children hunched shoulder to shoulder for long, grueling days over conveyor belts bearing raw coal as it emerged from the mine. They wielded pickaxes to split the larger chunks of raw coal and pulled out what rock (bone) they could see and pry free by hand. Elbow grease goes only so far, however, and the other coal-cleaning technologies of the day were primitive and typically reserved for highly priced metallurgical coal. Consequently, steam coal (if it was cleaned at all) reached most power plants in the same condition that it left the picking crews, harboring moisture, sulfur, and mineral impurities.

Times changed. Unions shortened the workday and advances in technology retired the pickaxe. Coal, however, remained the same—a dark, enigmatic, and wildly varying geologic relic. The boney pickers would wonder at the working conditions many of us enjoy today and at the sophistication of state-of-the-art coal-cleaning research and technology, but they would recognize modern coal immediately, brimming with the same imperfections that riddled the raw coal they struggled with a century ago.

Today's view

Coal's impurities are of greater concern than ever before because they complicate the task of cleanly and economically producing electricity from coal. Many of the richest and least expensive seams to mine have been depleted, particularly in the eastern United States, leaving deposits with higher levels of impurities, greater variability, and fewer Btu per pound than in the past. As mining has become more mechanized and safer, precision has been sacrificed for volume, producing run-of-mine coal with more debris from the floor and roof of mines than did earlier, labor-intensive mining methods.

Mineral impurities in the coal can produce slag, which can deposit on furnace surfaces, reducing heat transfer and damaging tubing, and (in some cases) lead to plant deratings. This slagging can force periodic load reductions or outages to clean the accreted material from furnace surfaces. Deratings and outages are expensive, and utilities are increasingly looking to coal cleaning as one way of minimizing their frequency and severity.

Sulfur dioxide and particulate emissions, if not controlled, contribute to air pollution. Water embedded in the coal and on its surface can freeze, hindering winter coal handling, and when coal is burned, evaporation of its moisture robs valuable energy. Quartz in raw coal wears down the pulverizers that grind the coal to prepare it for burning. And the weight of all these impurities increases coal transport costs.

If coal were a minor actor, its imperfections might be overlooked, but its role is too important. In 1984 U.S. utilities burned 664 million t of the black fuel, generating 1.3 trillion (10^{12}) kWh, or 55% of the nation's electric energy. The $22 billion per year spent by utilities for coal represents over 80% of the direct operating costs of the nation's coal-fired plants.

Getting the dirt out

About 35% of the coal bound for utility boilers receives some cleaning before it is burned. Most of the cleaning is performed on eastern and midwestern bituminous coal. Very little western coal is beneficiated in any way. The nation's 500-plus coal cleaning plants (most of which are operated by coal companies at the minemouth) rely primarily on physical processes that use differences in particle density to separate coal from its impurities.

Most cleaning plants separate coal into coarse (>10 mm), intermediate (10–0.6 mm), and fine (<0.6 mm) particle sizes. Of the coal that is cleaned, about 40% is in the coarse fraction, and the remaining 60% is intermediate or fine. Large debris (>10 cm) trapped in the coarse-mesh screen is often discarded. Coarse coal is most typically cleaned by pulsing water up through the coal in a device known as a jig. Impurities, such as shale (specific gravity around 2.5) and pyrite, the main source of sulfur in coal (specific gravity about 5.0), sink while the coal (specific gravity approximately 1.3) floats on top long enough to be scalped.

The other principal technology used to clean coarse and intermediate coal sizes is heavy-media cleaning. This approach uses a suspension of water and finely ground magnetite, which is denser than coal but less dense than coal's major impurities, to separate coal from mineral impurities. Coarse coal is cleaned in heavy-media baths. Smaller size fractions are swirled in heavy-media cyclones to speed the separation of coal from its impurities. The magnetite is rinsed from the coal and the refuse and then recovered magnetically.

Another device popular for cleaning intermediate fractions is the concentrating table—an inclined, vibrating platform with a diagonally grooved surface. Raw coal slurry is fed onto the high end of the table and flows down the surface. The shaking motion of the table stratifies the raw coal, with the heavy refuse particles on the bottom and the lighter particles on top. The coal particles are carried by the water flow over the grooves, while the heavier impurities are trapped in the grooves and conveyed off the side of the table by its vibrating motion.

Fine-coal particles are the most difficult to clean, because they tend to stay suspended with water in the cleaning process. Consequently, the fines are discarded at many coal-cleaning facilities. Because the fines contain up to 25% of the heating value of the raw coal, however, there is growing interest in recovering the combustible portion of these small particles. Fines are most frequently cleaned by coating them with oil and then agitating them in a tank of water, a process called froth flotation. The oil-coated coal particles are attracted to air bubbles that carry them to the surface. The impurities sink.

There are limits and trade-offs in coal cleaning. Organic sulfur and inherent moisture are bound in the molecular structure of the coal and cannot be removed economically. None of the physical separation processes is perfect—they all allow some impurities to remain in the cleaned coal and lose some valuable heat content in the refuse stream.

The challenge in coal cleaning is to economically remove as much ash and sulfur as possible while maximizing Btu recovery. Few of the currently operating coal cleaning plants are designed to achieve the optimal balance of Btu recovery and cleaning. Most use standard flowsheets (series of sizing, cleaning, and dewatering devices), which are geared to achieving specified ash or sulfur levels, often at the cost of a greater-than-necessary reduction in heating value.

Gathering the data

Utilities have recognized for some time that for coal cleaning to live up to its full potential, more has to be known about the composition of major coal types, their response to cleaning, and the performance of various cleaning technologies. To gather this information, EPRI, together with the Pennsylvania Electric Co., New York State Electric & Gas Corp., and the Empire State Electric Energy Research Corp., funded construction of the $15.2 million Coal Cleaning Test Facility (CCTF) near Homer City, Pennsylvania. CCTF, which is managed by EPRI and staffed by Raymond Kaiser Engineers, Inc., and Science Applications International Corp., is charged with characterizing the cleanability of U.S. steam coals, developing and demonstrating new and improved coal-cleaning technology and instrumentation, creating a national coal quality data base, and designing a model to enable engineers to better extrapolate the cleanability of specific coals from laboratory-scale tests.

CCTF is unique in that its cleaning equipment can be arranged in various sequences to produce over 50 different flowsheet configurations. This flexibility allows CCTF to perform a battery of tests from which the optimal cleaning method for a given coal can be determined. Since beginning operation in 1981 CCTF has run cleanability characterization tests on 20 major steam coals. These tests, conducted on 500–1000-t samples of coal donated by utilities, are broken into five parts: raw coal characterization, which analyzes the composition of coal; testing to determine whether froth flotation is warranted for the coal; impurities liberation characterization, which studies the degree to which crushing can release coal impurities; flowsheet testing, which measures the coal's response to various cleaning processes; and comparison of the coal's combustion properties before and after cleaning.

Coals vary widely in their composition and cleanability. It appears that in many high-sulfur coals, cleaning can reduce sulfur content by up to 50% while maintaining 90% or more of the heating value. After separating out the easily removed pyritic sulfur, however, additional sulfur removal is difficult. Studies on some moderate-sulfur coals have shown that increasing sulfur removal from 30% to 50% can reduce Btu recovery from 90% or better to only 50%.

CCTF's goal is to characterize from six to eight commercially important steam coals a year. Test results are being compiled in a national coal quality data base. This data base (currently available in hard copy from CCTF) will make utilities and coal companies more aware of the potential for coal cleaning and of the best methods to use in cleaning a given coal. Although CCTF will never be able to test all the nation's coal seams, it will characterize many large tonnage samples of major, representative steam coal types. By comparing the results from laboratory washability tests (costing $10,000–$15,000) with full-scale coal cleanability characterizations (up to $300,000), CCTF is developing a coal-cleaning plant performance model. This model will enable utilities or coal companies to better judge the cleanability and cleaning cost of a given coal on the basis of relatively simple, inexpensive laboratory tests.

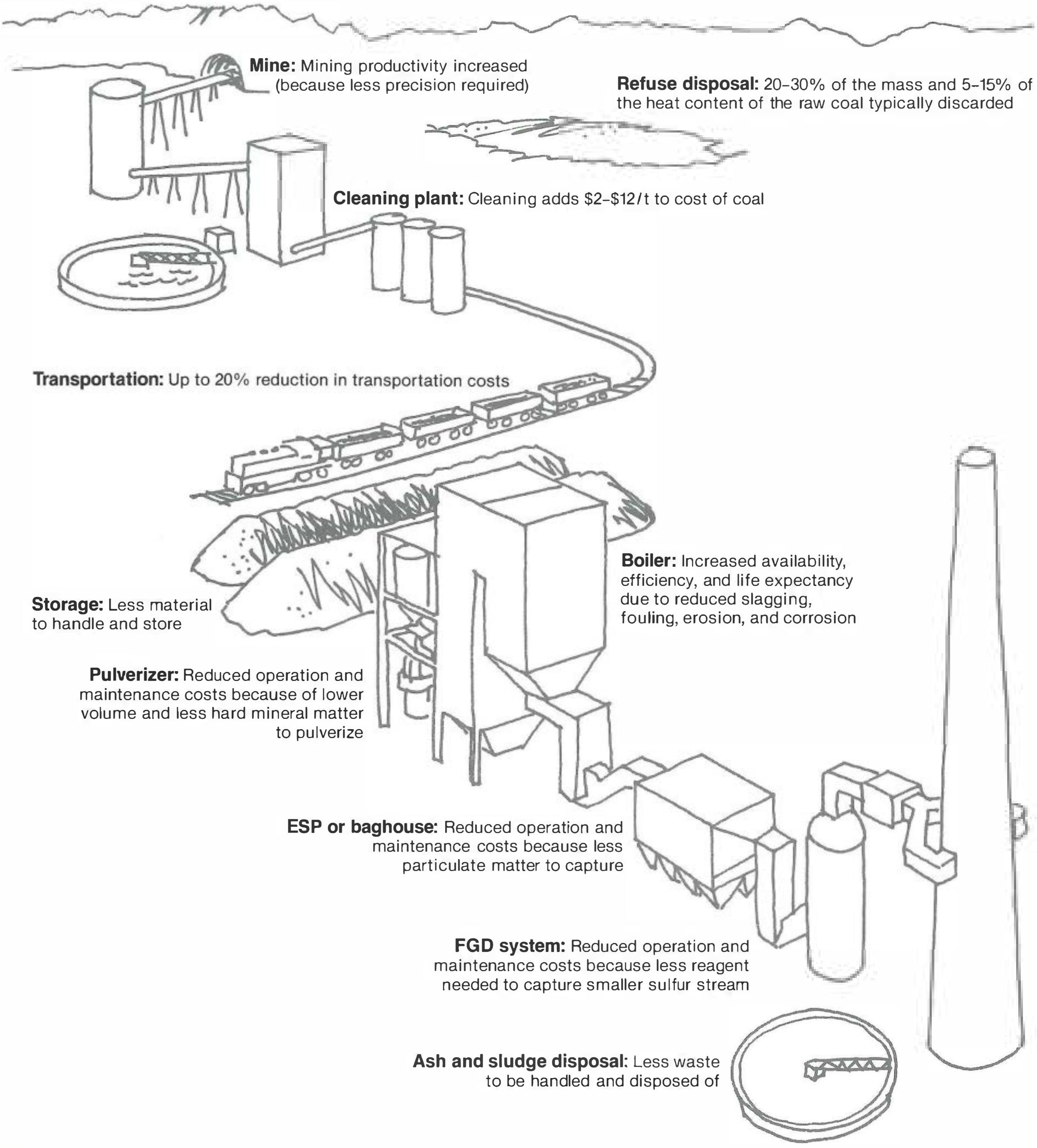
"Although there are important improvements in technology to be made, especially in the cleaning of fine coal," states Clark Harrison, "with only 35% of utility coal currently being cleaned, the greatest potential in coal cleaning lies in getting more utilities and coal companies to do even rudimentary cleaning. The characterization tests, data base, and predictive model will provide the performance information the industry needs to make informed decisions about coal cleaning."

Revolutionary advances in physical coal-cleaning technology are unlikely in the near term, but significant incremental improvements in the efficiency and cost-effectiveness of cleaning processes are being made. Nearly a dozen newly developed cleaning and dewatering technologies have been tested at CCTF in the last three years. These range from devices to improve magnetite recovery in heavy-media cleaning to a high-speed centrifuge for dewatering cleaned coal and instruments for measuring the flow rate and density of coal slurries. In addition to its own technology R&D, CCTF is cooperating with DOE to test advanced prototypes for fine-coal cleaning.

DOE launched two new coal-cleaning programs in 1985. The first is the cooperative testing effort with EPRI. The second, the advanced systems for producing superclean coal, is awarding several million dollars in R&D grants to support new coal-cleaning technologies. According to Richard Hucko, coordinator for the coal preparation project at DOE's Pittsburgh Energy Technology Center, "DOE is looking for advanced processes for supercleaning coal as part of its effort to mitigate acid rain precursors and to help reduce the use of oil and gas in electricity generation."

Tracking the Costs and Benefits of Coal Cleaning

About one-third of U.S. steam coal (over 200 million tons) is cleaned to remove ash and sulfur impurities and to increase the coal's heating value (Btu/lb). Most of the costs of coal cleaning are borne by mining companies, who build and operate the cleaning facilities and dispose of the refuse removed from the coal in the cleaning process. The mining companies pass some of these expenses along to utilities in higher coal prices. Utilities are burning more cleaned coal each year because they find that the savings it offers in fuel handling, plant efficiency, availability, and environmental controls compensate for the added fuel cost.



Cleaning in context

Just as DOE is not concerned with coal cleaning per se but wants the benefits cleaning can offer, utilities do not necessarily want cleaned coal—they want fuel that performs well, allows them to meet air quality standards, and results in minimum generation costs. Coal cleaning is one means of meeting these goals. Utilities have other options as well, all of which they consider as they make coal purchasing decisions.

Utilities can burn coal with high levels of sulfur and ash and then strip these impurities in the combustion chamber or from the flue gas with pollution control devices. Because coal with lots of impurities is usually less expensive than low-sulfur and low-ash coal, the savings associated with buying raw coal and cleaning it may compensate for the more extensive pollution control measures required when low-grade coal is burned.

Conversely, utilities may choose to spend more on, say, western coal, much of which is naturally low in impurities, enabling them to save money by installing less-sophisticated pollution control devices. When sulfur emission regulations were first promulgated, some utilities quickly signed long-term contracts for low-sulfur western coal without conducting any detailed characterization of the fuel they were buying. Some of this coal turned out to contain such alkaline earth elements as sodium (which reduces the ash melting point, thus promoting fouling or slagging) and chlorine (which causes furnace corrosion). One Illinois utility experienced such intense slagging and reduced Btu content with a western coal of this nature that it had to derate a 900-MW plant by 60%, or to 360 MW. Other utilities, conversely, have had good experience with western coals.

Utilities also have the option of buying coal that has been cleaned to a specified sulfur and ash content or to clean it themselves. Depending on transport costs and the degree of cleaning required, it may be less expensive for a utility to buy a cleaned eastern or midwestern coal than to purchase low-sulfur western coal. Some utilities in economically depressed regions are committed to buying from local coal suppliers and would rather pay a premium to clean local coal to their specifications than switch to other sources.

Cleaning cannot serve as the sole sulfur control measure for new plants, however. The New Source Performance Standards require that 70–90% of the sulfur in coal burned in new plants be captured, no matter how low the mineral content of the coal. Coal cleaning can rarely cost-effectively remove more than 60% of the sulfur from coal and thus must be combined with other measures, such as FGD scrubbers, to achieve regulatory compliance. The optimal fuel selection approach thus varies from station to station and depends on a host of factors ranging from transport costs and raw coal composition to coal price cycles, regional politics, and environmental regulations.

There is no general rule that tells when and to what degree coal should be cleaned. Some coals respond well to certain cleaning techniques; others are difficult to improve. There are over 100 major coal seams in the United States, and even within the same seam, coal quality and cleanability can range widely. The industry is thus refining its ability to judge how best to clean a given coal before it builds a cleaning plant.

Economics of coal cleaning

The capital cost of cleaning equipment, operation and maintenance, and the lost heating value of discarded coal are the factors that principally determine the cost of coal cleaning. A cleaning plant will cost 1–5% as much as the power plant it is designed to serve, depending on the level of cleaning and the quality of the coal being processed. Thus, a $10 million to $50 million cleaning facility can clean the coal for a $1 billion power plant. These costs can be offset somewhat by an effective increase in mine productivity because the cleaning plant can compensate for the mining company's lack of selectivity. When the capital and operating costs of cleaning plants are added to Btu losses in discarded coal and are levelized over the facility's service life, they add $2–$12/t to the cost of coal.

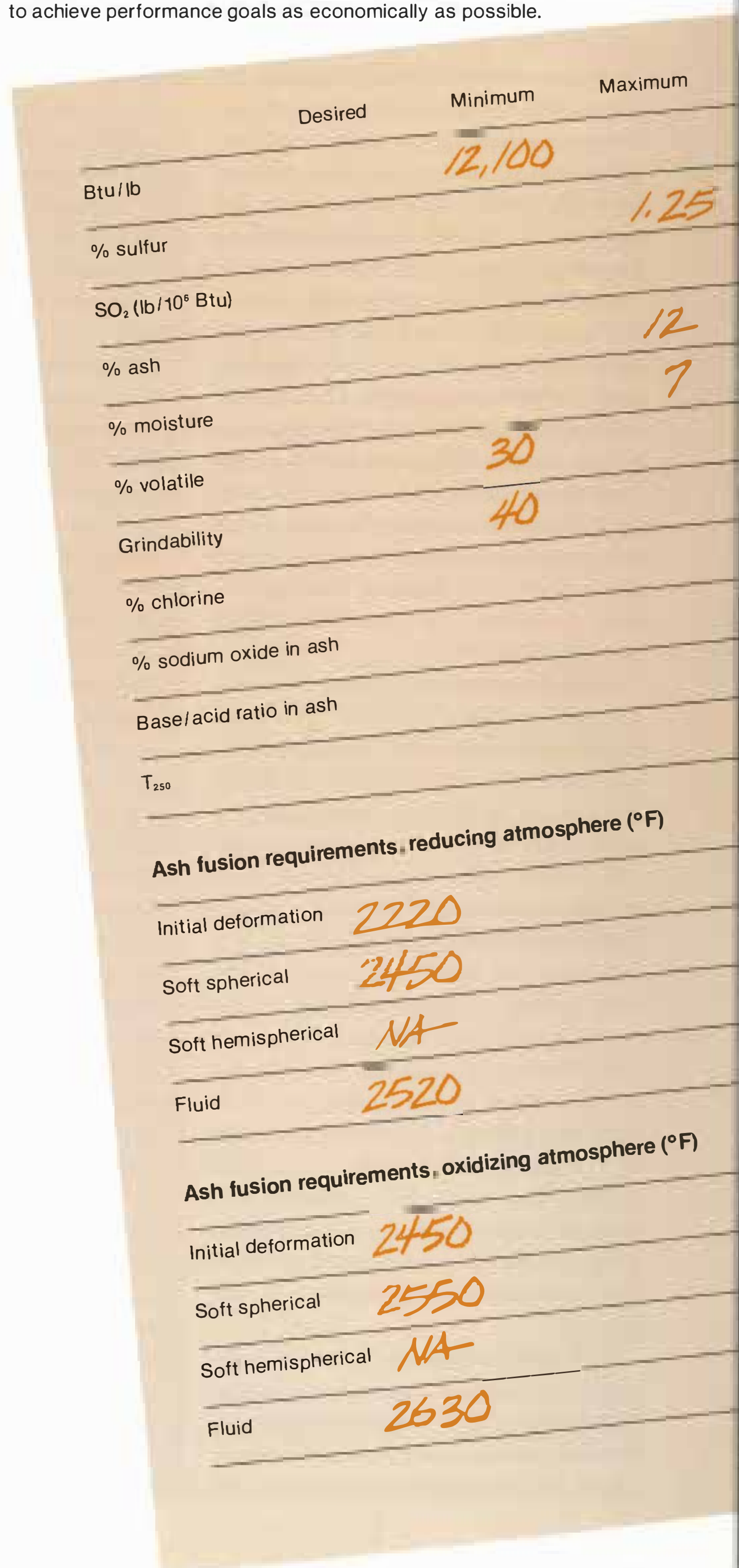
Cleaning can provide savings in several ways. It can reduce transport costs by around 20% (up to $2/t) by eliminating weighty impurities from the coal. It can reduce operating and maintenance costs in various ways, including reducing the amount of reagent needed to remove sulfur dioxide, and thereby minimize the amounts of dry waste and sludge that must be disposed of. Coal cleaning can reduce the capital costs for new power plants because boilers can be built more inexpensively if they are to burn a more consistent quality of coal, and the FGD equipment and coal, ash, and waste handling systems can be smaller.

An EPRI-funded report published in 1981 examined the above-mentioned costs and benefits of applying coal cleaning to new coal-fired power generation. The study examined seven hypothetical 1000-MW power plants (various plant locations and coal types) built to operate in compliance with federal air quality laws. For each hypothetical mine–power plant combination, calculations were run, assuming no coal cleaning, partial cleaning, and intensive cleaning in conjunction with particulate and sulfur dioxide controls. Intensive coal cleaning was more economic than using raw coal in four out of seven cases, equal in cost in two other cases, and more expensive in one case.

The 1981 report provides a consistent calculation method for comparing the cost of cleaning coal to the savings from transportation, smaller plant components, simpler SO_2 control, and smaller waste volumes. However, because the greatest net saving in the seven cases was 2 mills/kWh (levelized cost), these benefits alone are unlikely to be the key factors in a utility's decision to burn cleaned coal. Of greater significance are

Boiler Coal Specifications

As utilities come to better understand the relationship between coal quality and plant performance, they are developing more exacting specifications to guide their fuel purchasing. Traditionally, utilities have specified only three or four properties, such as Btu, sulfur, and ash content; but some are now considering a dozen or more criteria to achieve performance goals as economically as possible.



	Desired	Minimum	Maximum
Btu/lb		12,100	
% sulfur			1.25
SO_2 (lb/10^6 Btu)			
% ash			12
% moisture			7
% volatile		30	
Grindability		40	
% chlorine			
% sodium oxide in ash			
Base/acid ratio in ash			
T_{250}			

Ash fusion requirements, reducing atmosphere (°F)

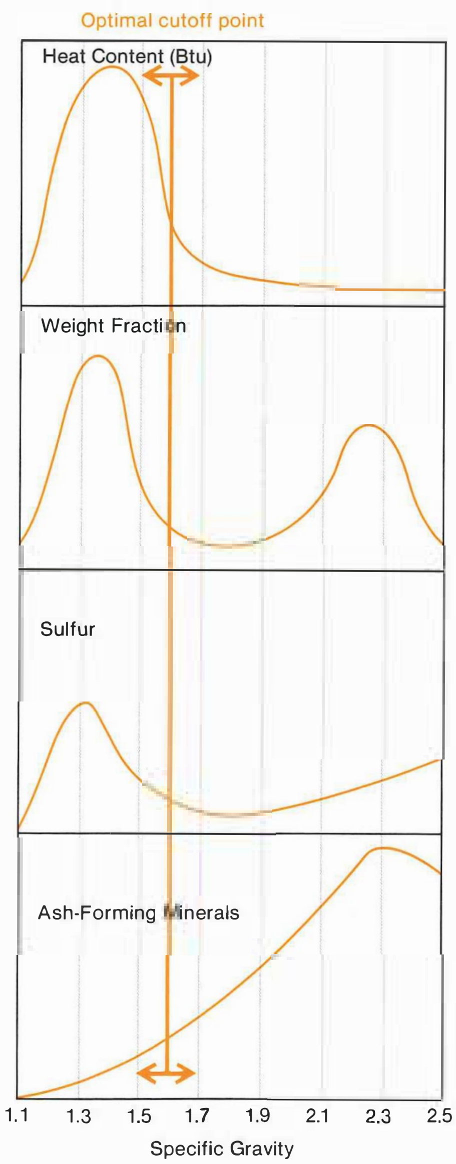
Initial deformation	2220
Soft spherical	2450
Soft hemispherical	NA
Fluid	2520

Ash fusion requirements, oxidizing atmosphere (°F)

Initial deformation	2450
Soft spherical	2550
Soft hemispherical	NA
Fluid	2630

Coal's Profile

The principal challenge in coal cleaning is to optimize the trade-off between removing as much of the ash-forming minerals and sulfur impurities as possible while retaining 90% or more of the coal's heat content. This is accomplished through physical processes that separate the high-Btu carbon compounds (specific gravity near 1.3) from the low-Btu impurities, most of which are heavier (specific gravity near 2.5). The optimal cutoff point determining what fraction of the coal is kept and what fraction is discarded varies with specific coals and plant conditions.



potential performance improvements at new or existing plants through reduced slagging, fouling, erosion, and downtime.

Quantifying these performance benefits, however, is a complex task. Several EPRI-funded research projects are now under way to define the relationship between coal quality and such plant performance criteria as capacity, heat rate, maintenance, and availability. Results from pilot-scale combustion tests on 20-t batches of coal will be extrapolated to predict performance impacts of coal quality in full-scale operation. These extrapolations will be refined through comparison with the results from full-scale field tests in actual power plants. The ease and accuracy of performing full-scale tests will be improved by a set of test guidelines being developed with EPRI support. These guidelines will instruct utilities on how to monitor the effects of coal characteristics on slagging, fouling, erosion, corrosion, mill wear, and other operational factors.

Coals (in run-of-mine and cleaned conditions) are being tested in pilot-scale combustion facilities by Combustion Engineering, Inc., and the Massachusetts Institute of Technology. Preliminary results on the few coals tested thus far indicate that by deep cleaning the coal, capital costs for the boiler, pulverizer, waste, and environmental control systems on a new plant can be reduced by up to 20%, with typical savings expected in the 5–10% range. Early combustion testing in a pilot-scale furnace has shown that a 50% reduction in ash content can typically be expected to improve the capacity of a slagging-limited boiler by at least 5–10%. The tests also showed that abrasion/erosion of boiler tubes and mill parts is reduced by a factor of 2 or more. Further testing is in progress on a variety of coals.

To simplify the utilities' efforts to make well-informed decisions on fuel selection and cleaning, EPRI is also funding development of a coal quality impact methodology. This computer-based model will

COAL CLEANABILITY CHARACTERIZATION

All coals were not created equal. Raw coal is a heterogeneous mixture of materials, including carbon derived from the plant matter that decayed to form the coal, sulfur, various minerals, and moisture, as well as rock and dirt inadvertently removed from the mine along with the coal. Coal cleaning succeeds to varying degrees in removing some of these impurities from the coal before it is burned. The chemical form of the impurity and the way it is physically bound in the coal influence how easily that impurity can be removed by physical cleaning processes.

For instance, sulfur is found in coal in three forms. Organic sulfur is molecularly bound in the coal carbon structure. Sulfate and pyritic sulfur generally appear as distinct particles mixed throughout the coal. Most of the sulfur in coal is pyritic or organic; sulfates generally appear in small amounts. By breaking the coal down into small pieces, coal cleaning liberates some of the pyritic sulfur particles from the coal, enabling cleaning processes to separate them from the coal. No amount of pulverizing, however, can liberate molecularly bound organic sulfur. The degree to which sulfur can be removed from a coal depends largely on the relative distribution of pyritic and organic sulfur.

Similar principles apply to the response of coals to techniques for removing ash-forming mineral impurities. If the impurities are large, distinct particles, they are fairly easy to remove. If they are small particles or are bound molecularly with carbon, they are difficult to extract.

Because coal composition varies so widely among regions and even within a single seam, rigorous testing of large samples is required to accurately assess the cleanability of a given coal. Until CCTF was built, there was no facility capable of running large samples of coal through the full battery of tests needed to accurately assess cleanability. One of CCTF's main tasks is to characterize major coal seams and to compile the results in a national coal cleanability data base.

CCTF has thus far completed tests on 20 major coal seams. The results of these tests indicate that few generalizations can be made about coal cleanability. In some coals, such as Upper and Lower Freeport, over half of the sulfur and from one-third to one-half of the ash can be removed while recovering over 80% of the heating value. With the Stockton-Lewiston seam, however, sulfur removal beyond 20% is achieved with a sizable 40% loss of heating value.

There is no escaping the laws of nature—coal variability is here to stay. With enhanced testing capability, however, the coal and utility industries can quantify that variability. For the first time, decisions about coal purchasing, beneficiation, and use can be made with sound advance information on the properties of a given coal. This capability is a major achievement in the search for cleaner, more economical ways of producing electric power. □

help utilities to predict how power plants will perform with different coals. Users will enter details about the boiler and other plant components, as well as the characteristics of the coal being considered. The model will then use this input to project how the plant will perform when burning that particular coal. As with the pilot-scale combustion tests, the accuracy of this methodology will be evaluated through field testing. Work on this project began in August 1985; a preliminary working model is expected in early 1987. Further field tests and R&D will be needed to refine the first version of the model.

Although broad claims about coal-cleaning economics cannot be made without further study, some recent case studies illustrate the potential for coal cleaning to save utilities considerable sums of money. The Keystone and Conemaugh plants in Pennsylvania are owned by a group of utilities in the region and operated by the Pennsylvania Electric Co. The Keystone station has two 850-MW units that burn coal from underground mines adjacent to the plant. Until a few years ago, the coal burned at Keystone was not cleaned; all the raw coal coming out of the mine was crushed and then fed directly to the boilers. Supported by information gained through coal cleanability characterization at CCTF, management at the Keystone plant decided to install a simple, inexpensive ($6.5 million) jig to provide rudimentary cleaning. The ash content of the fuel fell by 2–4%, the heating value of the fuel rose by 300 Btu a pound, the power output of each unit increased by 30 MW, and maintenance and outages were reduced considerably. David Eckelman, administrative manager for the Keystone-Conemaugh projects, states that "the addition of coal cleaning at Keystone was a very successful move for us. The annual savings to our customers will equal the entire cost of the cleaning plant."

The Conemaugh plant also burns deep-mined coal from dedicated mines adjacent to the plant. For many years, this coal was cleaned with relatively inefficient air tables, which removed some of the major impurities but discarded a lot of high-Btu coal in the process. Aided by CCTF analysis, heavy-media cyclones were added to recover burnable coal from the air table refuse. This addition proved to be a sound investment. "In reducing fuel cost by 5% per million Btu the cyclone will pay for itself in two or three years," states Eckelman. The heavy-media cyclones have also given the plant operators greater flexibility in the mix of coals they can burn and still comply with sulfur dioxide control regulations. Moreover, improvements in the quality of coal have the potential to improve performance and reduce maintenance costs at the plant.

Eckelman points out that the economic viability of coal cleaning is highly site-specific. "At Keystone," he says, "it was pretty easy to make significant gains because we started from a position of doing no cleaning at all, and we were working with a coal that responds well to basic cleaning. Cleaning won't necessarily work as well in other settings."

One of the key elements in successful coal cleaning is proper design of the cleaning facility. CCTF can help in this area by running tests to evaluate flowsheet combinations for a given coal. Armed with this information a utility can design a cleaning plant that will most cost-effectively improve that type of coal. But a utility or a coal company considering an investment in a coal-cleaning plant will want more than design optimization before it proceeds—it will want to know how much such a cleaning plant will cost.

In 1983 EPRI contracted with Bechtel Group, Inc., to meet this industry need by developing a model to estimate the capital and operating costs of coal-cleaning plants. The coal-cleaning cost model workbook produced in this study will be available in early 1986. The workbook includes technical and cost data on most elements in modern coal-cleaning plants. The data are presented for plants capable of cleaning 300–2000 t/h of raw coal. The accuracy expected for this quick, feasibility-level cost analysis is plus or minus 20%.

Future applications

Coal cleaning has come a long way since the days of pickaxes and hand labor, and it will remain an important practice for as long as coal is used to produce electricity. The current generation of coal-fired plants will give way to new technologies. Some will turn coal into gas or liquid; others will burn solid coal in new ways. Whatever their technology, these new processes will be affected by the quality of the raw material that fuels them. Coal cleaning will be a key element in optimizing the economical performance of twenty-first century power generation, building on a tradition established by the boney pickers of a past generation. ■

Further reading

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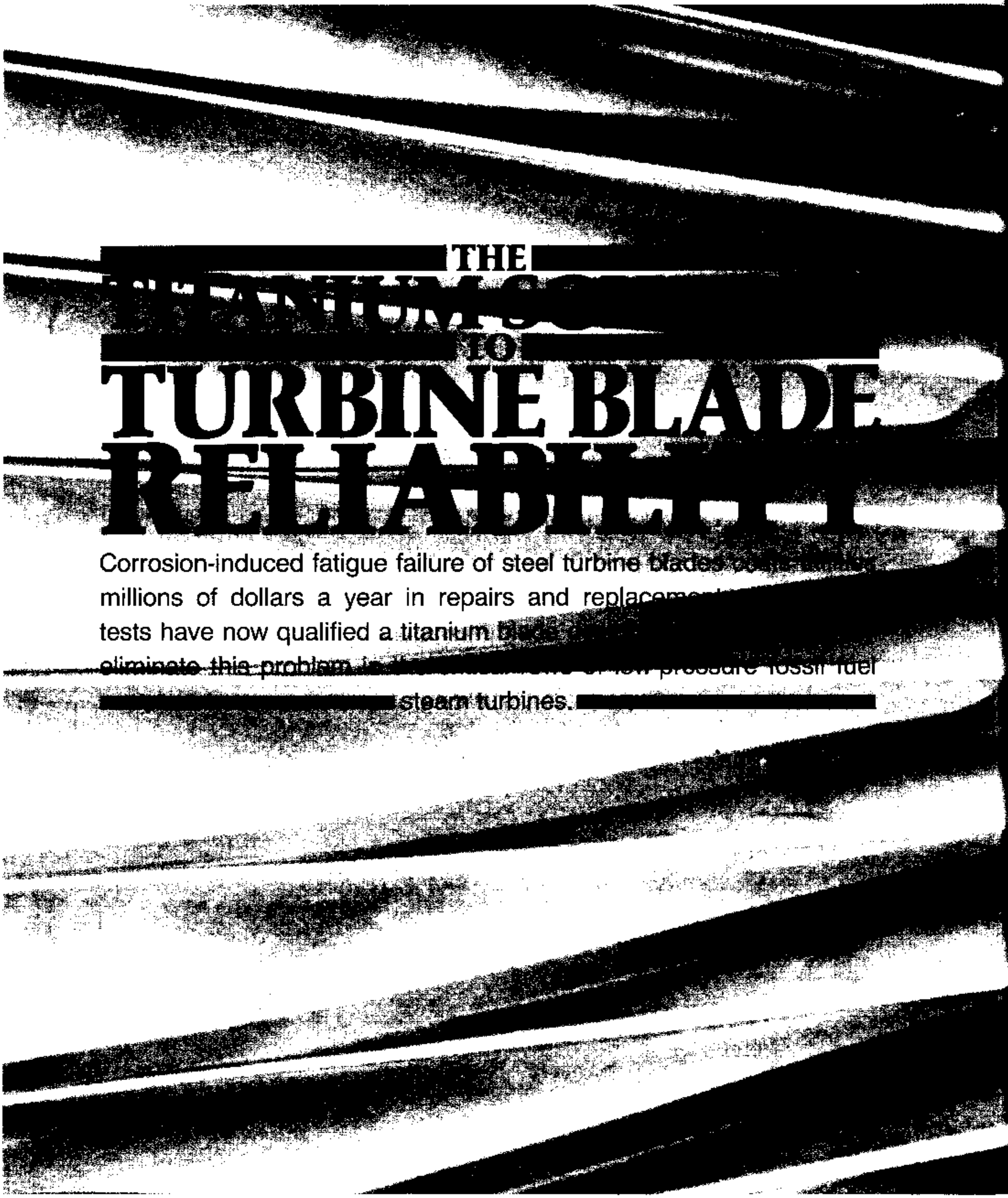
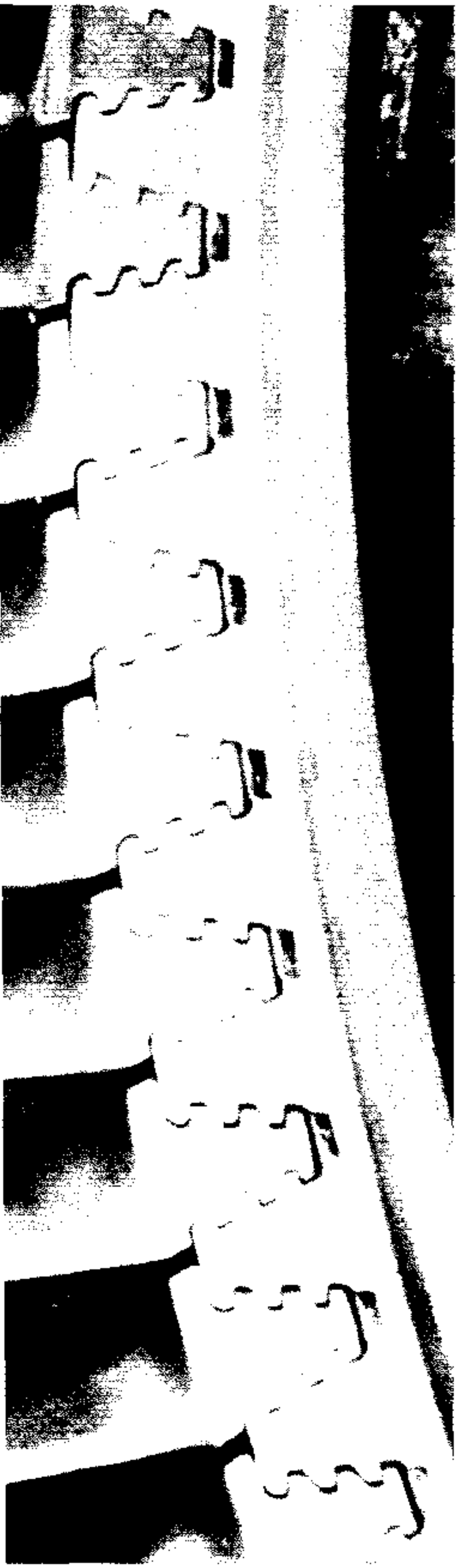
This article was written by Michael Shepard. Technical background information was provided by Clark Harrison, James Hervol, Frederick Karlson, and Michael Miller, Coal Combustion Systems Division; and the Coal Cleaning Test Facility staff.



THE TITANIUM SO[illegible] TO TURBINE BLADE RELIABILITY

Corrosion-induced fatigue failure of steel turbine [illegible] millions of dollars a year in repairs and replacem[illegible] tests have now qualified a titanium bl[illegible] eliminate this problem i[illegible] of low-pressure fossil fuel steam turbines.



Titanium has been used for 30 years in jet aircraft engines and missiles for its high strength-to-weight ratio, a density about half that of steel, and a high resistance to corrosion. During this time, numerous other uses for titanium have been explored and many are now commonplace: airframes for both commercial and military planes; sundry parts of spacecraft; assorted valves, pumps, and pipes for handling seawater in naval vessels; reaction vessels used in chemical processing and petroleum refining; the pigment in nearly all white paint; and prosthetic surgical implants are just a few examples.

Titanium is no stranger to the electric utility industry. The metal is used as tubing in the steam condensers of many nuclear and fossil-fuel-fired generating plants and is also found in key components susceptible to corrosion in geothermal circulation pumps. Now, as a result of an eight-year, $4 million joint research effort by EPRI and Westinghouse Electric Corp., another utility application of titanium has been demonstrated and verified: as a substitute for steel in the most failure-prone row of blades in low-pressure steam turbines.

Soon, titanium blades for the critical next-to-last (L − 1) row of low-pressure (LP) turbines will be commercially available to utilities as an option for dealing with corrosion and fatigue problems. Forced outages in an LP turbine can cost from $300,000 to half a million dollars a day. Although titanium blades cost from two to three times more than steel blades, prevention of even one day's forced outage would justify the extra expense. Moreover, the potential for virtually eliminating LP blade failures by substituting titanium for steel could pose a convincing economic argument to utility managers with fresh memories of recent blade failures.

For the moment, it is no small achievement that titanium has been tested and qualified as a blade material for L − 1 rows. In addition to years of painstaking analysis and testing that drew on expertise both here and abroad, EPRI pioneered research to improve the metallurgical and mechanical properties of the metal during processing and forging so that a consistent and uniform small-grain microstructure is maintained.

Further, to verify the blade material and design under realistic operating conditions, a row of one hundred twenty 16-in (41-cm) titanium L − 1 blades was installed in a Texas Utilities Generating Co. (Tugco) turbine in late 1984 for full-scale testing. With those tests completed, the titanium blades will remain in service indefinitely for long-term evaluation of their performance. "We can now say with certainty that titanium's unique corrosion resistance and fatigue properties warrant its consideration by utilities as an option for addressing L − 1 blade failures," says John Parkes, program manager for availability and life extension in EPRI's Coal Combustion Systems (CCS) Division.

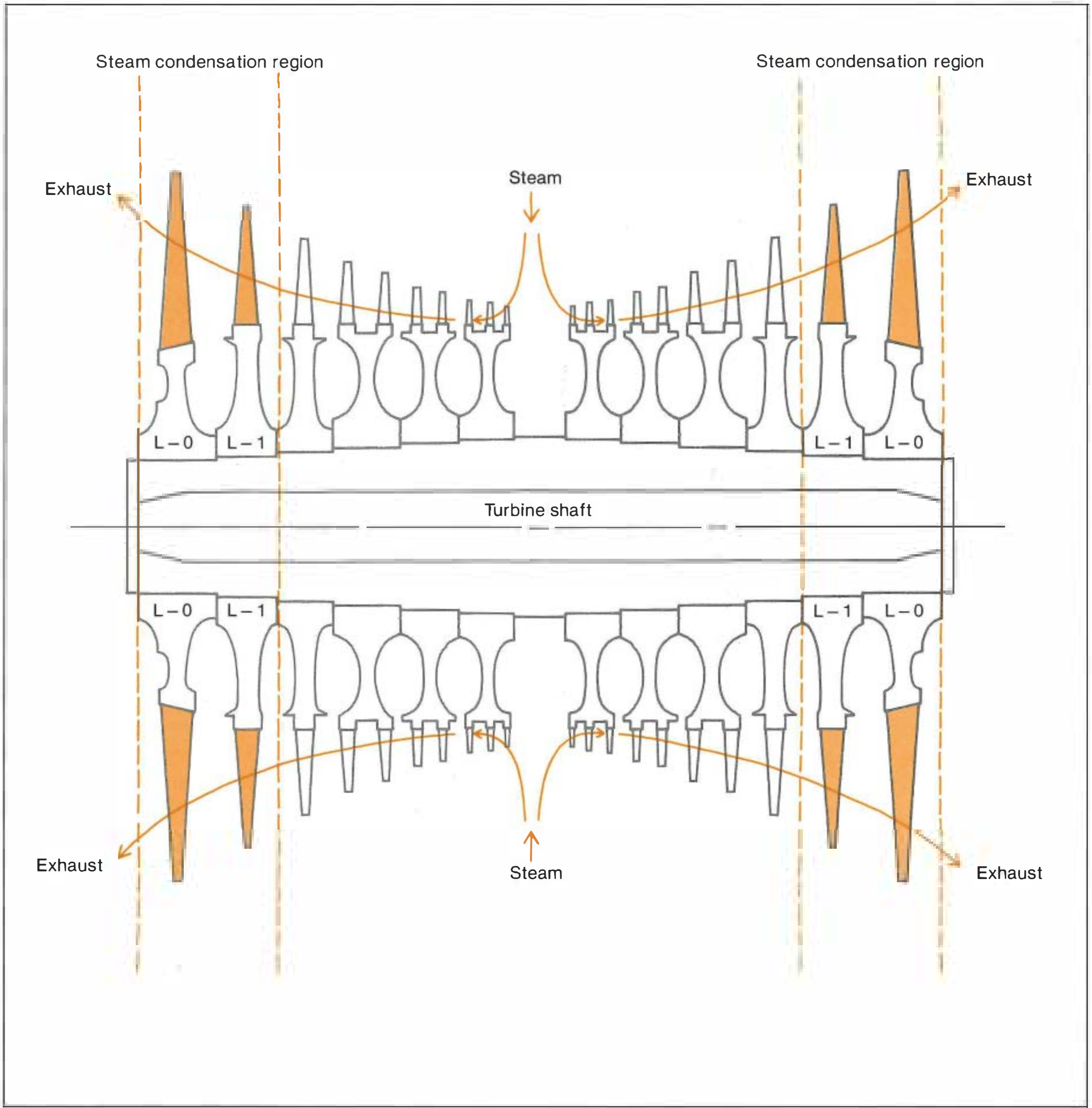
Besides being a significant development in advanced materials application, qualification of the titanium alloy Ti-6Al-4V (containing 6% aluminum and 4% vanadium) as an L − 1 turbine blade material also comes as a personal triumph for one of EPRI's senior technical advisers, Robert Jaffee, who has devoted the majority of his 43-year professional career to understanding and applying the special qualities of, as he describes titanium, "this most interesting and useful metal."

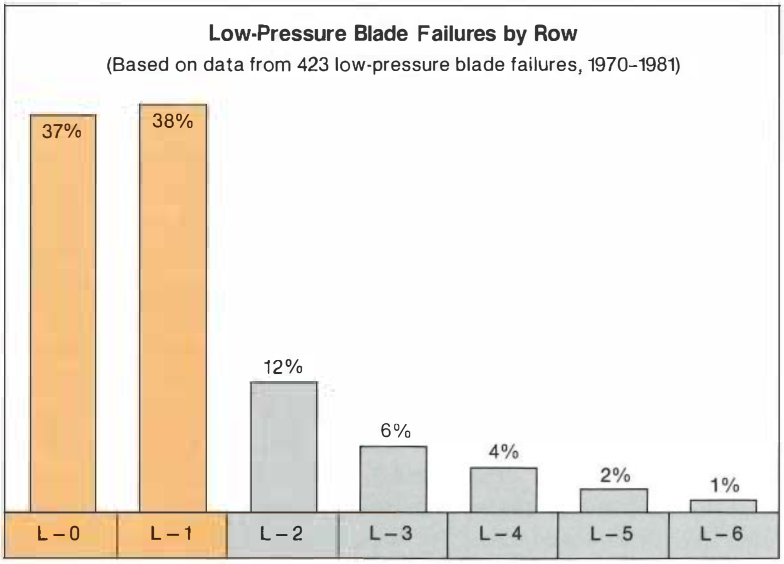
Jaffee, whose name can be found on the original 1956 patent for the widely used Ti-6Al-4V alloy (among the 45 or so patents that he holds), was a central figure in the post–World War II research community, alerting government and industry to the special appeal of titanium. Since joining EPRI in 1974, he has been a leader in application studies, particularly in electric power generation, that take advantage of titanium's unique character.

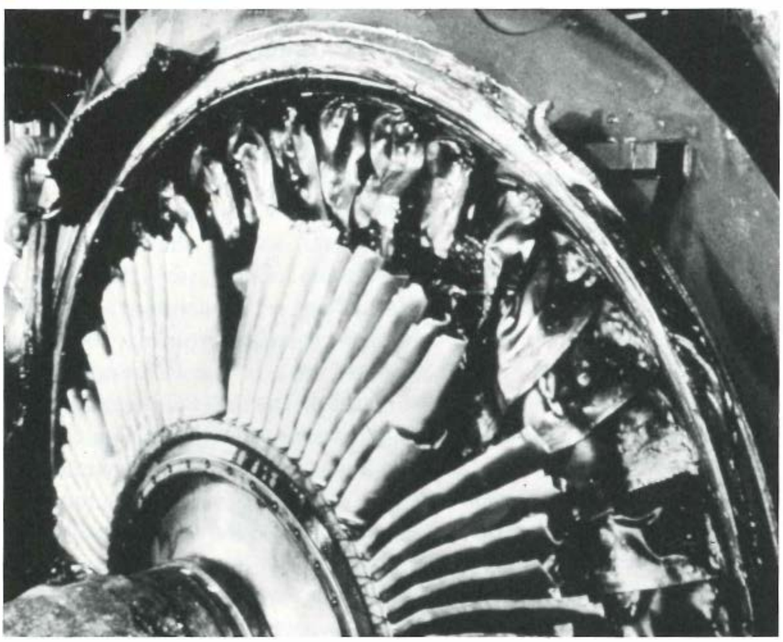
Jaffee is optimistic about the prospects for increased use of titanium in utility steam turbines. "We've made the open-

Blade Failures Take a Toll

A recent EPRI survey of 423 low-pressure turbine blade failures in nuclear and fossil fuel units 300 MW and larger found that three-fourths of all failures between 1970 and 1981 occurred in the last two blade rows. This is because for most low-pressure turbines, the last two rows are situated in the region where steam begins to change from dry to wet form; during this condensation, corrosive steam deposits precipitate in high concentration onto the surface of the blades and greatly reduce the fatigue strength of conventional blading steels. Blade repair and power replacement costs accounted for lost industry revenues of $1.4 billion over the 11-year period. EPRI's development with Westinghouse of a corrosion-resistant titanium blade for the next-to-last (L – 1) row could eventually lead to a similar blade for last-row application.







ing technical breakthrough to demonstrate the capabilities of titanium turbine blades. EPRI has sponsored some excellent laboratory work and carried it through production and demonstration.

"Titanium blades have been tested extensively in steam turbines over the past 20 years, and there has never been a failure reported. There have been two turbines in the United States equipped with titanium blades. Now, with the EPRI-Westinghouse tests with Tugco, there are three turbines so equipped, and we will be the first to provide the full technical details. My feeling, based on the properties of the material, is that the titanium blades will outlast the turbine," adds Jaffee.

The toll of blade failures

Development of blades that could outlast steam turbines designed to operate almost continuously for 30 years or more would be no mean feat, considering that turbine blades now fail at a rate of about 40 incidents annually. LP turbine blade failure has been identified in EPRI studies as the single largest cause of reduced availability in large steam turbines. Despite forced outage rates that have declined overall in the last 15 years, availability for nuclear and fossil-fuel-fired units 300 MW and larger has remained less than 75% since 1974.

A recent EPRI-sponsored survey found that blade failures between 1970 and 1981 cost utilities more than $1.4 billion in repairs and power costs; a single blade failure costs an average of $200,000 to repair and $2.5 million for replacement power while repairs are being made. According to Thomas McCloskey, a project manager in the CCS division, "the survey further found that three-fourths of all turbine blade failures occur in low-pressure turbines and three-fourths of those occur in the last or next-to-last row of blades. In other words, fully half of all blade failures involve the last two blade rows."

Utility respondents to the survey identified corrosion and fatigue as responsible for about 30% of all reported blade failures; another 40% were attributed to unknown causes, which account for the large proportion (50%) of repeat or multiple blade failures.

Thanks in large measure to a wide-ranging EPRI program to identify causes and mechanisms of turbine blade failure as part of the search for solutions, utilities now know why LP turbines, and particularly the last two rows of LP turbine blades, are so prone to fail. It is the unique combination of fatigue stress on blades moving faster than the speed of sound; the corrosive, aggressive chemical environment of condensing steam; and the physical and mechanical properties of the blade material itself that prove so detrimental to the 12–13% chromium stainless steel typically used in LP turbine blades.

Together, these factors can lead to pitting of the 12-Cr steel surface, which in turn can promote incipient microcracking on the blade material. Eventually, under alternating stresses and corrosion, the microcracks grow to form visible cracks, which, if not discovered during a maintenance outage, are a precursor of failure.

Beware the Wilson line

The problem of turbine blade failures in large fossil-fuel-fired steam plants is particularly acute because of the increasing use of these units over the last 10 years for cycling or peaking capacity. Because these plants are designed to run as baseload units, the added thermal and mechanical stresses from frequent load shifts exacerbate the situation at the last two rows of blades, which are already subject to corrosion and fatigue.

A typical large (600-MW) fossil fuel steam generating unit contains two or more LP turbines, each having dual steam flows, that accept steam discharged from the intermediate-pressure (IP) turbine. Dry steam from the boiler enters a high pressure turbine at around 1000°F (538°C) and 2400–3500 psig (17–24 MPa). By the time it leaves the IP turbine and enters the LP turbine, it has cooled to around 500–700°F (260–370°C), and the pressure has dropped to about 150–200 psig (1–1.5 MPa).

As the expanding steam passes the last two of six blade rows in the LP turbines, the steam begins to transform from dry to wet. This transition region of initial condensation, known as the Wilson line, is the point at which soluble contaminants in the steam—acid chlorides, sulfates, and others—precipitate in high concentrations onto the surface of the turbine blades. Air that enters the turbine when it is not operating can oxygenate the condensed solution, making it even more chemically reactive.

In fossil-fuel-fired units with a single reheat, the Wilson line is located at the L − 1 row at full load; double reheat usually puts the transition zone at the last blade row. Cycling the plant between full load and partial load can shift the Wilson line upstream and downstream. "This causes alternate wetting and drying of the condensate deposits, an even more corrosive environment than would exist in baseload plants," explains Jaffee.

The aggressive corrosion environment at the last rows of LP turbine blades can cause conventional 12-Cr steel to lose as much as 80–90% of its fatigue strength (as measured in air). In recent years, Westinghouse has used a stronger, more corrosion-resistant steel, 17-4PH (precipitation hardening), but even that alloy—containing 17% chromium and 4% nickel—eventually succumbs to the interaction of corrosion and fatigue stress, as evidenced by several 17-4PH blade failures that have occurred after relatively short operating periods.

"Assuming that the blades are designed properly, there is no doubt that the present 12-Cr or 17-4PH blading steels would serve admirably in the L − 1 transition row if the initial condensate could be kept sufficiently pure," notes Jaffee. "The evidence from Japanese, German, and British experience shows that this can be done. But as we have found, the steam in fossil fuel plants in this country is not being kept that pure."

Jaffee and McCloskey point out that maintaining very pure steam conditions can be quite costly, requiring condensate polishing equipment, staff chemists, and round-the-clock, fastidious attention. Even then, equipment malfunctions and the like can cause upsets in steam chemistry that quickly negate the effect of good steam purity the rest of the time.

Southern California Edison Co. (SCE) recently worked with EPRI in a study of steam chemistry control and, by using newly developed ion chromatography, identified impurities in the chemicals used for the regeneration of the condensate polishers as the source of chlorides and sulfates that were causing a turbine blade corrosion problem in some of its LP turbines. SCE learned how to regenerate and operate its condensate polishers to eliminate this contamination and, in so doing, help avoid corrosive deposits on the turbine blades.

In addition, the work contributed to an interpretation of the results of concurrent research involving SCE, EPRI, and Westinghouse to evaluate various potential coating materials that can give greater corrosion protection to stainless steel LP turbine blades.

SCE currently has some 24 rows of blades coated with nickel-cadmium electroplate and ion vapor-deposited aluminum in operational testing. These blade coatings are an economical option for protecting against corrosion. The utility and EPRI are now documenting savings estimated on the order of several million dollars as a result of the coatings.

As reflected in EPRI's survey of steam turbine blading at fossil fuel and nuclear plants, utilities in the United States have various philosophies regarding maintenance. Some find it economical to invest in close control of steam purity, while others may choose more-frequent maintenance shutdowns for blade inspection and replacement. Still others may be willing to pay the price to put the turbine blade corrosion problem to rest for good.

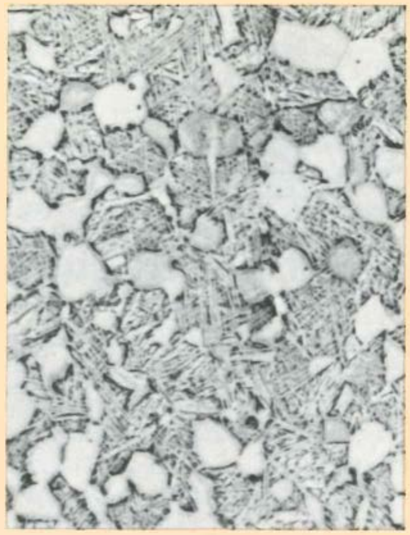
TITANIUM: A GIANT AMONG METALS

Named for the giants who ruled the earth in Greek mythology, titanium is the fourth most abundant metal in the earth's crust, following aluminum, magnesium, and iron. There are two main titanium minerals: ilmenite ($FeTiO_3$), and rutile (TiO_2). Both are mined extensively and chemically processed into titanium tetrachloride ($TiCl_4$), from which both pigment-grade titanium dioxide and titanium metal are produced.

Titanium was discovered in 1789 by William Gregor, an English clergyman and sometime mineralogist, and named titanium six years later by the German chemist Martin Klaproth. Metallic titanium of sufficient purity to be malleable was not produced until the 1930s—by Matthew Hunter, using sodium reduction of $TiCl_4$, and by Wilhelm Kroll, using magnesium reduction. Both processes are still used today, but there is growing interest in an electrolytic process similar to that used to refine aluminum and magnesium.

Metallic titanium by the Kroll process was first produced for sale in 1950 by the E. I. DuPont de Nemours Co. Titanium metal is now produced by four organizations in the United States and by many more abroad. Production capacity for titanium sponge (an intermediate form) is now about 200 million pounds (91 Mt) worldwide, of which about 60 million pounds (27 Mt) is produced here.

Because of a shortage of refined titanium sponge in 1980–1982 caused by high demand for aerospace applications, the United States increased its production capacity by 50% and Japan doubled its capacity. As a result, there now is a worldwide oversupply of titanium sponge, and the industry is operating at about 50% of capacity. "This is fine for potential users, such as the utility industry," says Jaffee, "because it ensures a stable supply of raw material at a low price." Titanium mill products cost about the same as comparable nickel-base alloys.



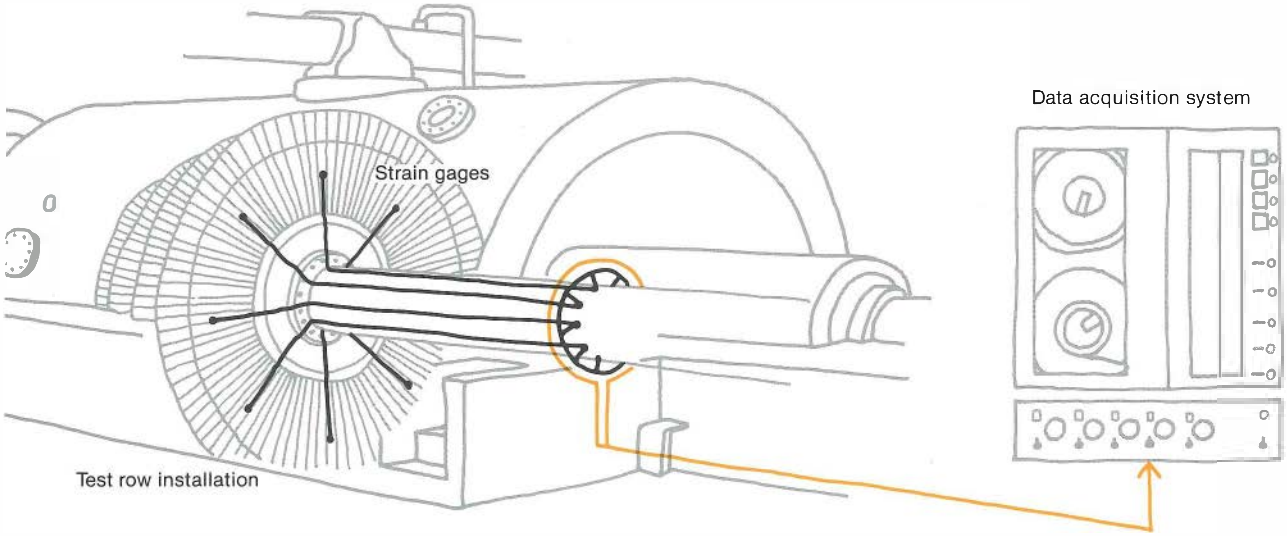
40 μm
(13/16 in)

Aerospace applications account for about three-quarters of the market for titanium, and industrial uses account for the rest. Of the aerospace applications, about half to two-thirds are in military aircraft, with the rest in commercial aircraft. The industrial market for titanium—primarily for chemical plant operations and heat exchangers—has grown 13% a year over the past 15 years. The LP turbine blade application is for alloyed titanium, an alloy similar to those used extensively for jet engine compressor blading.

The basis for most of the structural blade applications of titanium alloys lies in their superb combination of high strength-to-weight ratio and corrosion resistance in chloride salts. The fatigue strength of titanium is about 25% higher than that of the common 12-Cr blading steel and is relatively unaffected by the acid chloride environment found at the steam transition in LP turbines. Because 12-Cr steel may lose three-fourths of its fatigue strength in the turbine environment, the environmental fatigue strength for the titanium alloys becomes fivefold better than for 12-Cr steel.

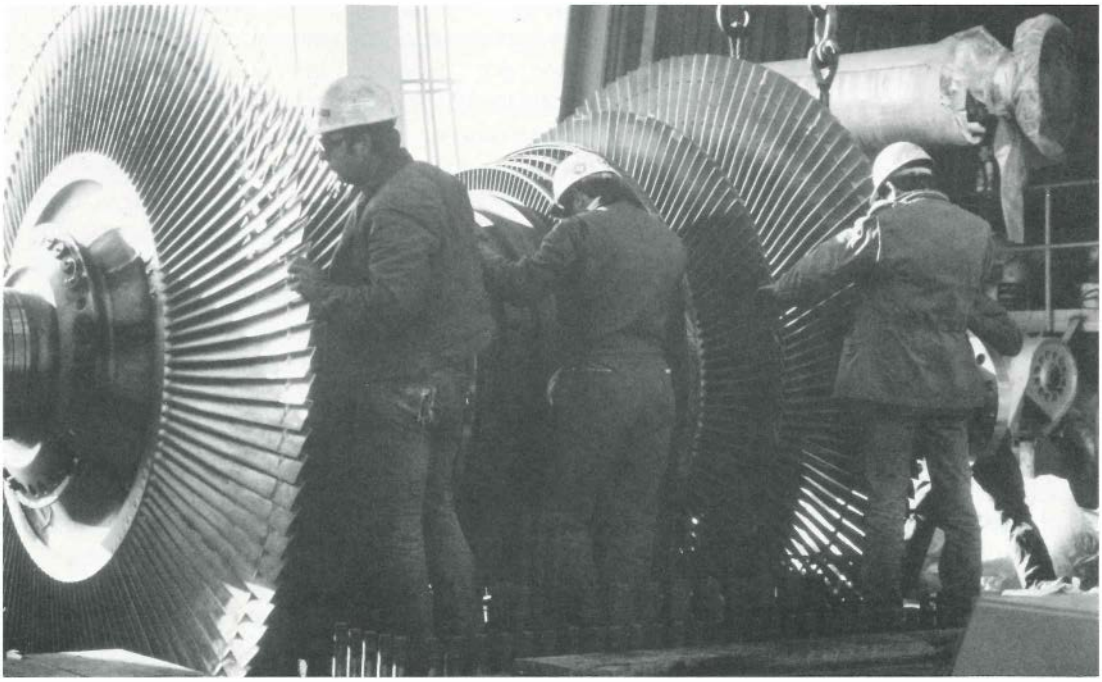
At about 1800°F (280°C), titanium alloys undergo an allotropic transformation similar to that which occurs during the heat treatment of steel. "The transformation is extremely useful in producing fine-grained microstructures, which are important in developing good combinations of strength, ductility, and toughness," notes Jaffee. "The bimodal microstructure developed under EPRI support is a good example of how the transformation may be used to manipulate microstructure."

The corrosion resistance of titanium is the basis of many of its applications. Titanium is immune to most alkali halides, except fluorides. It has excellent resistance to most oxidizing acids, such as nitric acid, but is attacked by concentrated mineral acids, such as hydrochloric and sulfuric. Many industrial applications of titanium involve the inhibition of acid corrosion through the complexing action of metal ions (such as copper, iron, and cobalt) that may be present. This is the basis for the excellent field test experience for titanium in scrubber applications under conditions in which laboratory tests indicate that rapid attack should occur. □



Telemetry Testing at Tugco

A complete row of one hundred twenty 16-in L – 1 blades made of the Ti-6Al-4V alloy was installed for field telemetry testing in late 1984 in the low-pressure turbine at Texas Utilities Generating Co.'s Martin Lake Unit 3. A row of 17-4PH steel blades of similar design was installed at the turbine's opposite end for comparing vibratory stresses over a full range of possible operating conditions. Data from strain gages mounted directly on the blades were transmitted by FM radio signals to a stationary receiver outside the turbine casing for collection and analysis. The telemetry tests dispelled concern about titanium's damping capacity and qualified the blade design for L – 1 application. Westinghouse intends to offer the blade commercially for turbines experiencing severe service conditions.



EPRI-Westinghouse 16-in titanium blades installed in a low-pressure turbine rotor disk.

That approach implies substituting titanium for steel as a blade material.

Long-standing power industry interest

A 1976 survey conducted for EPRI by Battelle, Columbus Laboratories showed that steam turbine makers all over the world are interested in titanium blades, and some have had test rows in operation for as long as two decades. The Soviets and the Swiss have installed last-stage blade rows of titanium, including very long (50 in, 127 cm) last-row blades of large (1200-MW) turbines running at 3000 rpm.

In Japan (already a major producer of titanium metal and active in its application in industrial equipment) several industrial firms are known to be keenly interested in titanium as turbine blade material. Titanium tubing is used in the condensers of steam turbines manufactured by Hitachi Ltd., Toshiba Corp., Fuji Electric Co., Mitsubishi Heavy Industries Ltd., and others (including Westinghouse in the United States). A 50-MW Mitsubishi turbine equipped with titanium last-row blades is operating at the Kobe Steel Works in Kakogawa, and Mitsubishi has indicated it is developing a 40-in (102-cm) last-row titanium blade for 3600 rpm turbines.

The Soviet Union reportedly uses titanium routinely as blade material, as well as for other turbine components, in 500-MW turbine-generators. It is also said to be testing 800-MW and 1200-MW units equipped with titanium blades.

In Switzerland Brown, Boveri & Co., Ltd., of Baden has been active in development of titanium blades since 1960, and it has operated small (65-MW) turbines equipped with titanium blades since 1962. The firm reportedly has studied the susceptibility of such blades to wet steam droplet erosion and has concluded that they require no added shielding because of titanium's naturally high erosion resistance.

In 1980 Brown Boveri installed two rows of 18-in (46-cm) titanium L − 1 blades in the LP turbines of a 1300-MW plant at American Electric Power Co.'s (AEP) Mountaineer generating station at New Haven, West Virginia. After 17 months and 12,000 hours of operational testing, Brown Boveri pronounced itself satisfied with the metallurgical behavior of the Ti-6Al-4V alloy, as well as with its vibrational and fluid-mechanical design. Inspection revealed no sign of corrosion and only light traces of droplet erosion at the blade tips. One of the two titanium blade rows installed at Mountaineer remains in service today, and the other was removed for installation in another AEP unit.

There is substantial other experience with titanium turbine blades in the United States. Initially, much of the interest by American turbine manufacturers in titanium was for application as long last-row blades for large turbines, but the trend of the last 10 years in this country toward smaller generating units has tended to diminish some of the early enthusiasm for development.

General Electric Co. has tested titanium blades interspersed with steel blades in several 150–200-MW turbines, reporting no problems to date under basically continuous operation. Since the mid 1970s, General Electric has used titanium for the single closing blade in the L − 1 and L − 2 rows of hundreds of its turbines of various sizes. In addition, the company has investigated titanium for use in the heat exchanger of a turbine's electrohydraulic cooling fluid system.

Ingersoll Rand Corp. and Terry Corp., makers of smaller industrial and shipboard turbines, also have used titanium blades and blade covers, and both report no problems and excellent resistance to corrosion.

Like General Electric's, Westinghouse's interest in titanium goes back many years, to the time when the metal was seen as the essential blade material in the last rows of very large turbine-generator sets. But also like General Electric, the company has been cautious and conservative in considering titanium as an L − 1 retrofit material. Much of the reason for that caution has been that before any major American turbine maker commits to commercialization of titanium blades, it wants to be sure that the myriad mechanical performance features of such blades are fully understood.

To that end, in 1972 Westinghouse placed in service a set of 23-in (58-cm) last-row blades at Georgia Power Co.'s Hammond-1 generating unit. The blades, of the unshrouded design but with lashing wires to improve mechanical vibration damping, have been operating successfully ever since.

Despite the many experimental successes, American turbine makers have expressed continuing concerns about the mechanical properties of titanium blades under certain operating stress conditions. These relate to titanium's low vibration damping capacity. The concern is that the blade must be designed and tuned so that resonant vibrations are not produced at the first harmonics (multiples) of the running speed, which could result in stresses that greatly exceed the fatigue strength.

The only way to study these effects closely is to test the blades in an operating turbine. In what is known as telemetry testing, the turbine is heavily instrumented to transmit data on operating stresses and other factors from the rotating components to stationary parts of the turbine by radiotelemetry for recording and later analysis. Because of cost and the interruption of turbine availability during installation of the telemetry instrumentation, this technique is not normally used, but it was considered the last remaining task in what had become a long and successful R&D program.

Telemetry testing at Tugco

To get the necessary data that would confirm or dispel the remaining concerns about titanium blades, EPRI and Westinghouse sponsored the manufacture of a row of one hundred twenty 16-in (41-cm) L − 1 blades for testing in a turbine that was known to have had fatigue problems. By 1984 Tugco was on board with the project. The LP turbine of its 728-MW Martin Lake Unit 3 station near Tatum, Texas, was outfitted with L − 1 titanium blades in one steam flow and 17-4PH stainless blades of identical design in the opposite end of the turbine for direct comparison. The Martin Lake station had experienced a number of recurring L − 1 steel blade failures since the plant's initial operation in the mid 1970s.

The new titanium blades were designed to be freestanding to minimize centrifugal and corrosion-related stresses and were tuned through the first four modes of vibration in rotating tests at Westinghouse manufacturing facilities.

Both the steel and titanium L − 1 blades were equipped with resistance strain gages cemented at critical locations. Miniature FM radio transmitters picked up the signals for dynamic strain and vibration frequencies and transmitted data to recording instruments outside the turbine casing. Pressure transducers were placed on blade airfoils near the leading edge to measure circumferential stagnation pressure variations and identify sources of aerodynamic excitation.

For seven days in December 1984 the turbine was operated at varying speeds and four major series of tests were conducted. Operation of the turbine has continued since then for long-term assessment of blade performance. The blades will be inspected during regular scheduled maintenance shutdowns.

Results of the Martin Lake tests, now fully analyzed by Westinghouse, showed that operating stresses produced no more vibratory stress on the titanium blades than on the identical steel blades, indicating that titanium's lower material damping is not a serious concern. More important, the tests showed a factor-of-2 improvement in the actual-to-allowable stress ratio in the titanium blades compared with the 17-4PH steel blades.

Future sets of titanium blades will have the benefit of insights developed under concurrent, related EPRI research. Titanium produced by a duplex recrystalli-

GETTING TO THE ROOT OF BLADE FAILURES

Development and verification of titanium steam turbine blades are only one element of a broader effort in EPRI's CCS division to attack the problem of blade corrosion and fatigue. The various elements are intended to produce a range of options that utilities can consider in the context of turbine-specific assessments of cause, effect, and solution. These include research projects on analyzing and maintaining good steam purity to avoid corrosive blade deposits, blade coatings under development that promise to protect blades from corrosion, titanium as a substitute blade material, and a finite-element computer code for evaluating blade designs and diagnosing the root cause of failure.

"The right solution to a utility's turbine blade corrosion-fatigue problems depends on the utility, its equipment, its local water chemistry, and its maintenance philosophy," explains Parkes. "Utilities should use a root cause analysis approach to decide for themselves what is best. To help them do that, we think we have all the elements developed or under development that will let utilities independently evaluate their own situation."

One of these elements under development, but expected to be commercially available within a few years, is an interactive computer code for evaluating blade design and analyzing vibration-related failure. Called BLADE (blade life algorithm for dynamic analysis), the code uses finite-element techniques to create a dynamic model of a blade group for calculating vibration characteristics, including natural frequencies, mode shapes, and forced responses to applied excitation and blade damping. The excitation spectrum can be generated from actual turbine dimensions and operating factors.

"Utilities have repeatedly indicated that they need a method for predicting whether a flaw detected in an operating turbine blade during an outage would or would not be likely to lead to a failure before the next scheduled outage," reports McCloskey. "We think BLADE will provide that capability."

Developed for EPRI by Stress Technology, Inc., the BLADE code has already proved helpful to New Jersey's Public Service Electric & Gas Co. in troubleshooting a blade failure. Field demonstration and validation tests for L − 1 row application are scheduled late this year at SCE's Huntington Beach station. If those tests are successful, BLADE could be issued as a prerelease research code in 1986. A production-grade version will await additional verification testing under different applications and could become available in late 1987 or 1988. □

zation process that results in a consistently fine microstructure proved to be the key to controlling blade elasticity and, in turn, the natural frequency of vibration. EPRI achieved this further dimension of understanding with the help of Professor Gerd Lütjering, a leading metallurgical scientist in West Germany. His contribution to the L − 1 project is expected to benefit the turbine manufacturing industry worldwide as it gains increasing experience with titanium blades.

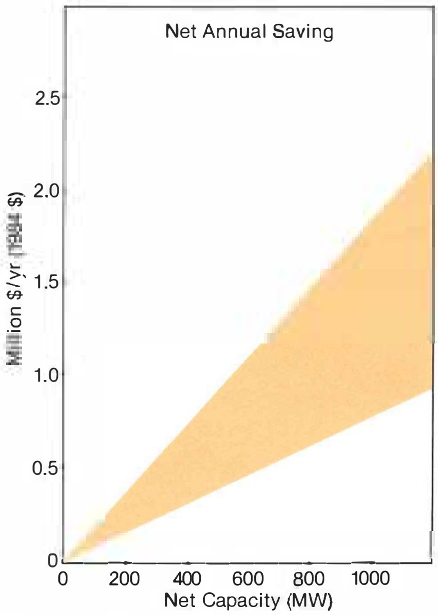
Nearing commercial availability

On the basis of the successful telemetry testing with Tugco, Westinghouse plans to offer commercial titanium turbine blades for L − 1 rows as an option for utilities with plants experiencing severe service conditions. According to John Traexler, manager of steam turbine generator engineering at Westinghouse's Orlando, Florida, power generation division, "Whatever technical questions we had before the Tugco testing have been resolved, and our earlier reservations about titanium's low damping capacity have been eliminated. Westinghouse intends to commercialize the titanium L − 1 blade, and we are formulating an implementation plan to do that."

EPRI's Robert Jaffee considers the test program a success as well. "On the basis of the installation at Martin Lake and the subsequent telemetry testing, we are now in a position to anticipate expanding commercial use of titanium in this application. If a titanium L − 1 row saves even a single day's forced outage over the life of the turbine, it will pay for its additional cost." EPRI and SCE have planned a three-day steam turbine blade workshop for next March in Los Angeles, when full technical results of the L − 1 project will be presented along with sessions on other aspects of EPRI's blade reliability program.

EPRI researchers point out that beyond the L − 1 application, titanium continues to hold promise for American utilities as a material for longer last-row blades in larger, higher-output turbines. Titanium blades are considered ideal for double reheat supercritical steam units, where the Wilson line occurs at the last row, as well as in higher-speed tandem compound LP turbines.

"But for the moment," says Parkes, "titanium has found a very special niche for the steam transition row in the power generation equipment market. It may be only the beginning, but now utilities have a proven option for dealing with the immediate problem of corrosion fatigue in turbine blades." ■



Potential Benefits of Titanium Blades

An EPRI assessment of the economic benefit from substituting titanium blades in the last rows of low-pressure turbines indicates a potential saving of from $500,000 to $1 million a year for a typical 600-MW coal-fired plant. The analysis assumed a 65% plant capacity factor with a 1% improvement in availability. Although titanium blades are expected to cost two to three times more than conventional stainless steel blades, the analysis indicates that the value of improved plant availability in one year would cover the extra cost of titanium substitution.

This article was written by Taylor Moore. Technical background information was provided by Robert Jaffee, R&D Materials Support; Thomas McCloskey and John Parkes, Coal Combustion Systems Division.

Further reading

Survey of Steam Turbine Blade Failures. Final report for RP1856-1, prepared by Stress Technology, Inc., March 1985. EPRI CS-3891.

The Effect of Variables on the Fatigue Behavior of Ti-6Al-4V. Topical report for RP1264-2, prepared by Battelle, Columbus Laboratories, October 1984. EPRI CS-2934.

Corrosion Fatigue of Steam Turbine Blading Alloys in Operational Environments. Final report for RP912-1, prepared by Westinghouse Electric Corp., September 1984. EPRI CS-2932.

Mechanical Properties of a Titanium Blading Alloy. Final report for RP1266-1, prepared by Technische Universität Hamburg-Harburg and Ruhr Universität Bochum, October 1983. EPRI CS-2933.

Status of Titanium Blading for Low-Pressure Steam Turbines. Final report for TPS 76-641, prepared by Battelle, Columbus Laboratories, February 1977. EPRI AF-445.

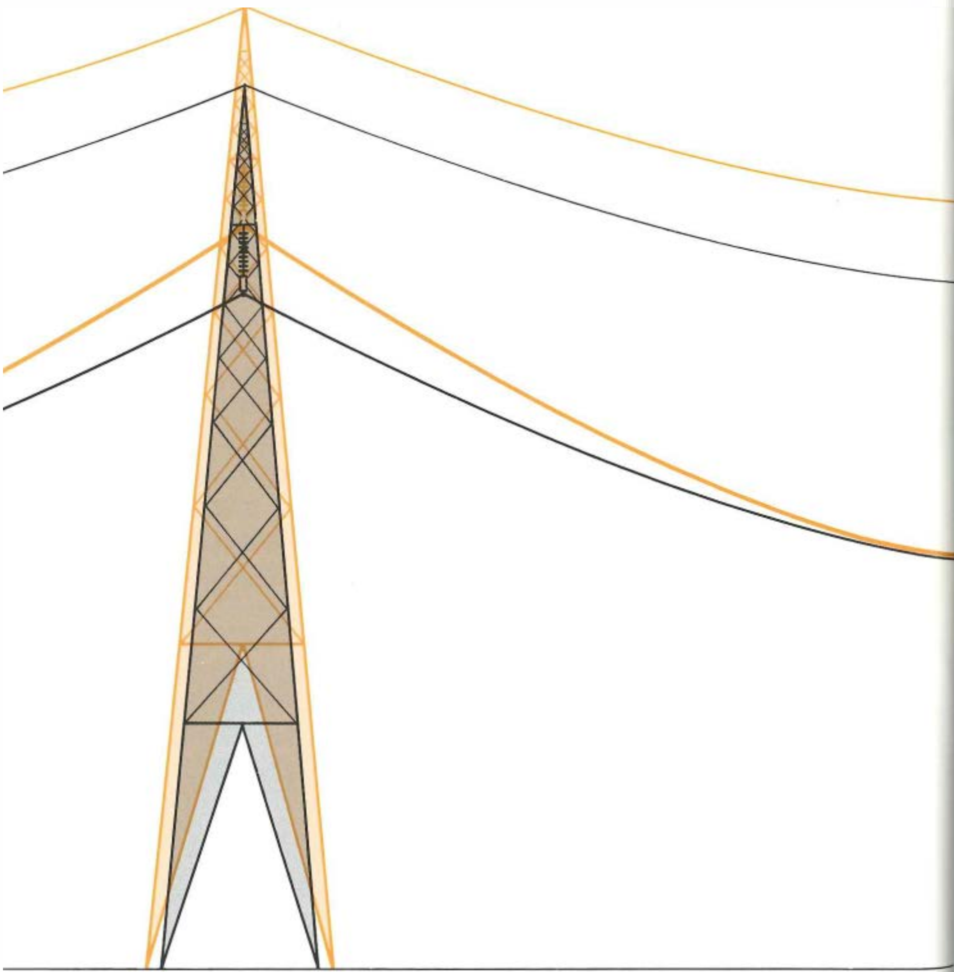
TRANSMISSION LINE UPRATING: STRATEGIC OPTION FOR SYSTEM PLANNERS

From 1965 to 1975, when demand for electricity was growing by 8% a year, utilities were scrambling to build the new transmission lines necessary to satisfy the ever-increasing demand. From 1975 to 1984, on the other hand, with almost no load growth nationwide, the need for increased transmission capacity was greatly diminished. Today, with an intermediate growth rate of 2–4%, utility planners are facing a considerably different situation.

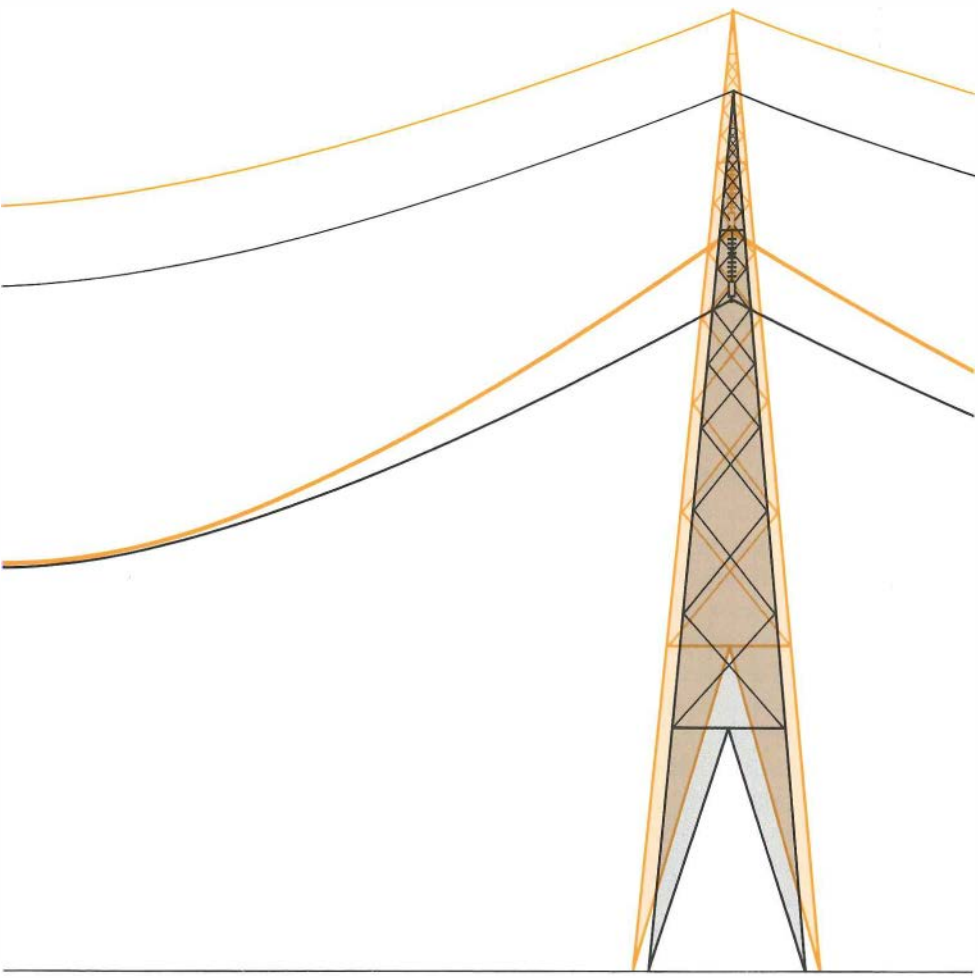
"This period of slow growth calls for a different approach," comments Richard Kennon, manager of EPRI's Overhead Transmission Lines Program. One important strategy is increased use of line upgrading or uprating. According to Kennon, utilities are now realizing that modifying an existing line can increase its capacity by 50% and defer major new investment by 10–15 years.

These two terms, *uprating* and *upgrading*, are often used interchangeably. Strictly speaking, however, uprating refers to any change that increases the power transmission capacity of a line. This can be done without making any physical changes. For instance, a line's capacity can be increased by simply allowing it to run hotter. Or major modifications in the line can be involved, such as replacing the conductor and strengthening the towers. Upgrading, on the other hand, refers specifically to structural modifications in a line. This can be done either for the purpose of uprating or for other reasons, such as correcting a weakness.

Line uprating and upgrading are nothing new. They have been part of industry practice for decades. But recently the pros and cons of uprating and upgrading are being given fresh scrutiny. There has been increased attendance at sessions dealing with this topic, and the general impression is that uprating and upgrading activity is picking up. In light of this new interest, EPRI is developing a family of analytic tools to help utilities plan and carry out such improvements with confidence and efficiency.



Increasing the rating of an existing transmission line may be cheaper and faster than building a new one, but it usually means upgrading the tower structures as well as stringing new conductors. EPRI computer programs are adding speed and precision to the upgrading design process.



Economic considerations

Although adaptation to a slow-growth environment, rather than to a zero- or a high-growth environment, is the major reason for the new allure of uprating and upgrading, a number of other economic and technical factors have also heightened utility interest in these alternatives. One important incentive is the current cost of electrical energy. There are over a hundred thousand circuit miles of transmission line that are more than a decade old. This means that the lines were built when rates were substantially lower than today, and designers did not give heavy consideration to reducing electrical losses. With new conductor designs that have substantially lower electrical resistance for the same diameter, replacing the conductors on many of these lines is possible with only minor structural changes.

The economic value of the reduction in line losses alone is significant enough to justify uprating and upgrading in many cases, according to Kennon. Clement Nadeau, a planner for the Niagara Mohawk Power Corp., agrees. "These days, a megawatt saved in losses is worth more than a megawatt in added capacity. Loss reduction is anti-inflationary; it reduces environmental effects, such as electric fields and radio interference. And," he adds, "it helps keep rates down."

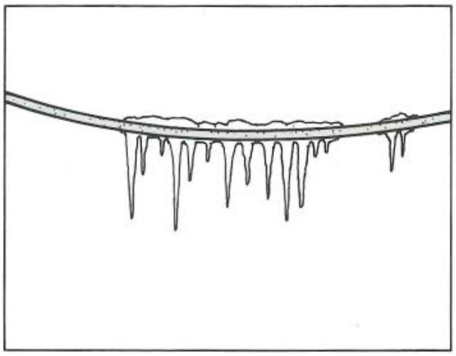
Skyrocketing right-of-way costs and reduction in lead time for licensing are further reasons for upgrading or uprating rather than building new lines. Although building a parallel transmission line normally requires acquisition of additional right-of-way, an upgrade frequently does not. Plus, it is generally easier and faster to get licenses for an upgrade than for new construction.

"On a dollar-per-kilowatt basis, uprating or upgrading is not always less expensive than new construction, but it generally does allow utilities to return facilities to service in a shorter period of time," says Nadeau, "and this enables them to react more quickly to a changing environment." In New York, for exam-

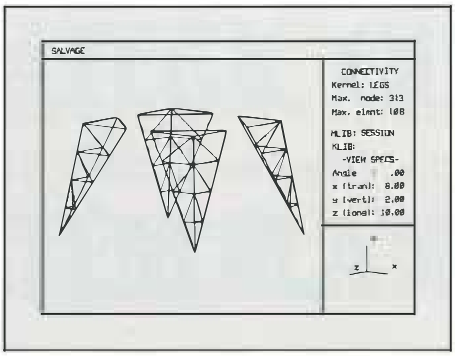
Five Principal Steps

Upgrading a transmission line design can be seen as a sequence of five distinct activities, which have been addressed by EPRI research. All but one activity can be expedited by computer techniques, and three can be carried out with programs in the TLWorkstation software library.

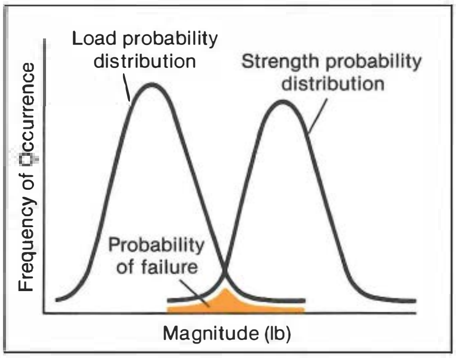
1 Determine structural loads. Employ new analytic techniques to interpret short-term wind data.



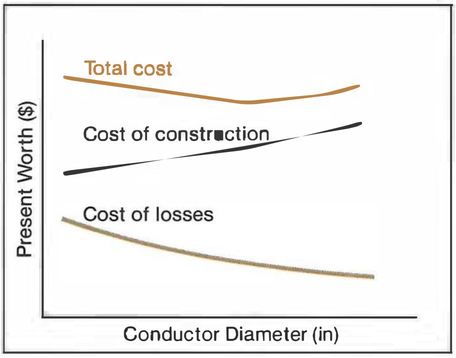
2 Analyze structural response. Model a tower with TAG, and check its behavior with ETAP.



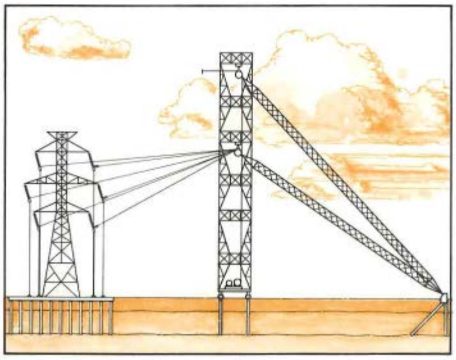
3 Perform a combined load and strength analysis. Use DESCAL for reliability analysis and design.



4 Select the proper conductor. Run TLOP to optimize electrical and structural capabilities and costs.



5 Evaluate the behavior of a full-scale structure. Use TLMRF test pads as development laboratory.



ple, the upgrade or uprate licensing process has a good chance of being expedited, in some cases without formal hearings. Such a project can typically be licensed in under a year, as opposed to the usual two years for getting approval to construct a new transmission line. In addition, uprates and upgrades generally take less time to construct and this shortens lead times even further.

Rapid response is critical in many of the current upgrade projects. Today, a number of utilities find themselves with a surplus of generation capacity. If they can sell this excess power to other utilities burdened by more-expensive generation costs, it can provide additional revenue. To realize this gain, however, utilities may have to increase their transmission line capacity. No one knows how long the current window of opportunity will last, so upgrades are favored because they allow companies to begin capitalizing on the situation quickly.

Economic transfers are the driving force behind many of the present upgrading efforts, as Nadeau points out. In rare cases, these projects can be dramatically cost-effective. As the result of a $100,000 upgrade of a short stretch of line from 69 to 115 kV, Niagara Mohawk is currently saving $5 million a year because the upgrade allowed the company to tap relatively inexpensive Canadian hydroelectric power. In most cases, however, the potential payback is substantially more modest.

Although upgrades are not necessarily less expensive per kilowatt than new construction, they require less capital investment. Today, many utilities are short of cash, so projects with a lower price tag look especially attractive. In a number of cases, transmission line modifications are proving exceptionally cost-effective, and in recent years considerable progress has been made in the ability to analyze the strength and loading of existing transmission line structures.

According to Kennon, this work suggests that many older structures are substantially overdesigned. Where this is the case, it is possible to exploit this excess strength, often reducing the cost of uprating and upgrading dramatically.

Uprating and upgrading are not panaceas. The process of altering existing lines has some decided drawbacks that must be taken into consideration. Building a new parallel line tends to increase system redundancy, whereas an upgrade tends to reduce it. Generally, modifying an existing line requires that it be taken out of service for a period of time, whereas building a new line can be done without temporarily decreasing the capacity of the existing system. In addition, an upgrade cannot increase system capacity as much as a new line, and the remaining life of the modified facility will be less than that of new construction.

Conditions in general seem more favorable for uprating and upgrading than they were in the past, but determining whether such a strategy makes sense in a specific case requires a complex economic analysis. The following examples indicate not only the benefits to be gained but also the diversity of considerations required for a decision to upgrade in specific cases.

Utility experience

In the case of the Pacific HVDC Intertie (the pioneer long-distance, high-voltage, direct-current transmission line in the United States), a series of upratings have been made to capitalize on the current surplus of inexpensive generating capacity in the Pacific Northwest, which is the result of lower-than-anticipated load growth in the region. This 850-mi (1370-km) line, which runs from Oregon to southern California, was built in the 1960s by the Bonneville Power Authority (BPA) and the Los Angeles Dept. of Water & Power (LADWP).

Originally, the Intertie was rated at ±400 kV and 1800 A. In 1979, after a series of tests, the line was uprated to 2000 A. Further study convinced engineers that there was sufficient margin to allow an increase in the line voltage to ±500 kV. The only physical change required on the line was putting new insulators on a 30-mi (48-km) stretch near Los Angeles, where the particularly bad air pollution tended to coat the insulators, increasing their tendency to flash over; insulators specifically designed to reduce particle buildup eliminated the problem. The major cost involved in the uprate was for the terminal equipment required to handle the higher voltage. The uprated line went into service last January.

According to John Vithayathil of BPA, this project had two basic economic benefits. The higher voltage increased efficiency and substantially reduced line losses, and the increased line capacity allowed greater transmission of less-expensive power from the Northwest to the Southwest. "With these changes we are transmitting 2000 MW with the same losses we had been experiencing at 1600 MW," reports Vithayathil. At the time the decision to upgrade was made, the median payback for the investment was estimated at 4.5–5 years, but the load factor is running much higher than anticipated so the payback period should be substantially shorter. To market even more of Bonneville's excess capacity, BPA and LADWP have begun a new project aimed at boosting the line's current rating by another 50%. This will increase line losses dramatically, but in this case, losses are not a major concern. If the hydropower is not used, it is just lost over the spillway.

An upgrade that involved a major modification of transmission line towers was performed by Utah Power & Light Co. (UP&L) in 1980. Here, speed was of the essence. The original 230-kV line in the Salt Lake Valley was constructed in the early 1960s. But when load growth outstripped projections, company planners asked for a 345-kV upgrade. The utility had most, but not all, of a parallel right-of-way purchased, and they wanted to preserve this for future expansion. Tearing down the existing 25-mi (40-km) line and totally replacing it had two major drawbacks. The existing line was only 15 years old and junking it would have meant a major accounting loss; the job would have taken a year, so the line would have been out of service during a peak demand period.

"Because the tower design had been optimized for the 230-kV case, at first I didn't think it had the strength to carry a heavier, bundled conductor," recalls Marlo Menlove, UP&L engineer. But the towers had been designed and analyzed by using older, drafting-table methods. With a newer, three-dimensional computer analysis, Menlove was able to come up with a unique design to support the extra load. This involved adding two extra legs to the sides of the four-legged tower, which supported the additional bracing required. When a tower was built to this design and tested in Canada, it withstood 115% of the design load.

The upgrade was made during a six-month period in 1980 with minimal difficulties. The process involved nearly doubling the weight of the towers from 10,000 to 19,000 lb (4.5 to 8.6 Mg). The process was relatively expensive because of the large amount of welding required and the fact that much of the work was done in the air. Still, the cost was more than balanced by saving the write-offs on the original structures and by the shorter construction time.

The Otter Tail Power Co. of Fergus Falls, Minnesota, is no stranger to the upgrading process. In the 1960s it upgraded 165 mi (266 km) of transmission line from 115 to 230 kV. In so doing it saved several million dollars. "The upgrade cost was about half that of constructing a second, parallel line," reports Myron Broschat, company engineer. This success encouraged Otter Tail to embark on a more ambitious upgrading program. This summer it will energize the first 70 mi (113 km) of a total 4200-mi (6760-km), 41.6-kV subtransmission line, which it is gradually upgrading to 115 kV. In 1976 Otter Tail built a three-quarter-mi (1.2-km) stretch of 115-kV test line and used the pole, insulator, and conductor design it had settled on for the new upgrade. After several years of operating this test line without problems, the company began the new upgrade. According to Broschat, Otter Tail is saving anywhere from 25 to 40% over the cost of new construction, depending on the amount of work that must be done on the existing line.

As these cases illustrate, uprates and upgrades can have decided economic benefits when conditions are right. In some respects, however, modifying existing lines can be more challenging than constructing new ones. Specifically, upgrading can present a major problem in coordination between planning and design staffs. With a new facility, utility planners can decide what is needed, and the engineers can design the transmission line that will do the job. Planning and evaluating an upgrade is not nearly so straightforward; the costs of various degrees of upgrade must be evaluated on a case-by-case basis. And it requires more coordination between the planning and engineering departments.

TLWorkstation*

Fortunately, there are new tools and techniques that facilitate the kind of "what if" thinking demanded by the upgrade process. An example of these new tools is an integrated package of computer programs currently under development by EPRI. Dubbed the TLWorkstation, the programs were originally conceived as aids to the construction of new transmission lines. But, according to Kennon, they are equally helpful in planning and evaluating uprating and upgrading. TLWorkstation is designed to provide the utility engineer with all the necessary planning, design, and analysis capacity in a single, consistent, and user-friendly software package.

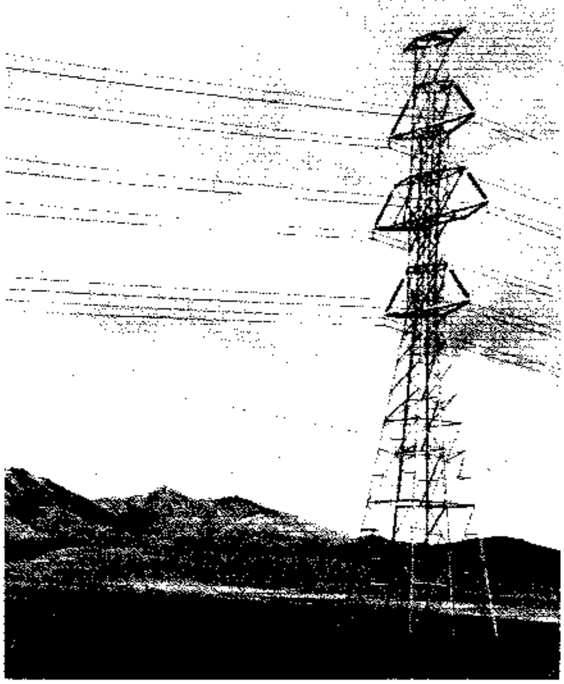
The core of the package is the tower analysis generator (TAG), which enables engineers to model the three-dimensional truss and frame structures used in transmission line tower construction. Using computer graphics, an engineer can build up extremely complex structures with relative ease. Once the user is satisfied with the model, he can determine its behavior under load by using a second program, the EPRI tower analysis program (ETAP). After this is done, results can be displayed in terms of deflected shape plots and stress summaries.

"When existing structures are analyzed by state-of-the-art analytic software of this sort, the chances are good that engineers will discover they have capacity beyond what was originally calculated," Kennon observes. One area of over-conservatism frequently found in older structures concerns the assumptions underlying calculations of wind and ice loadings. Today, weather data are not more abundant, but interpretive methods have been vastly improved. In particular, one of EPRI's projects has made significant strides toward predicting 50–100-year maximum winds on the basis of as little as three years of wind data by analyzing monthly rather than yearly variability.

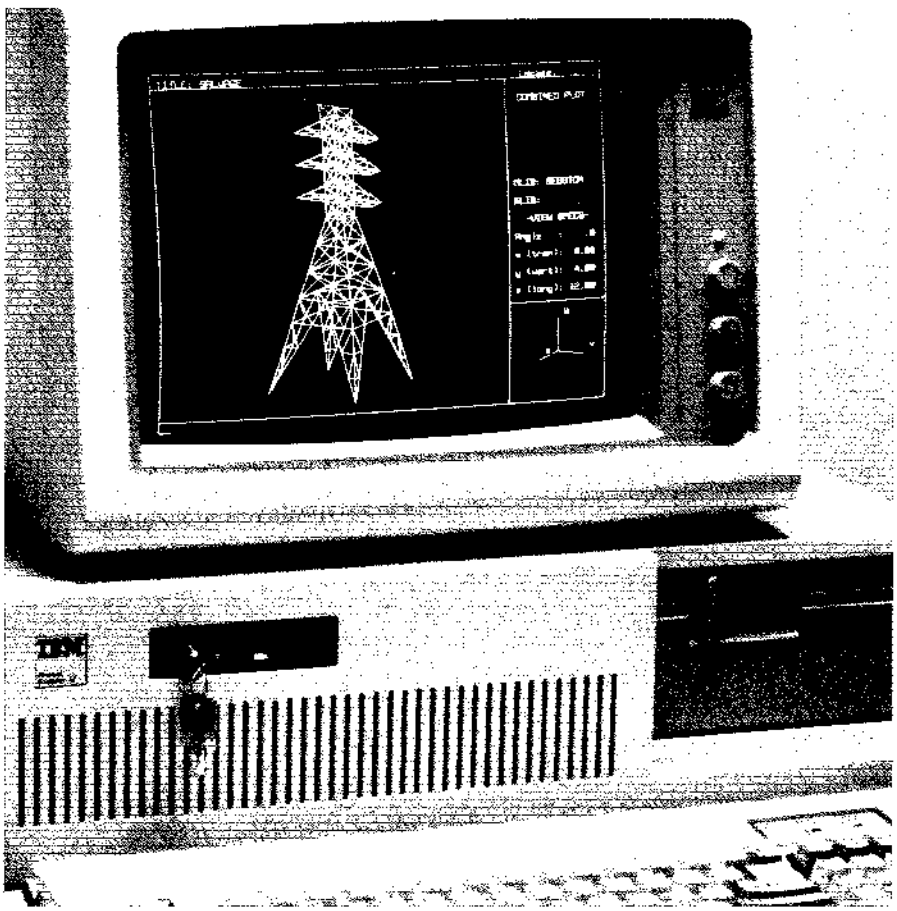
The traditional approach to calculating the loads a structure could withstand was to take "the worst of everything: the worst wood, the weakest steel, and so on, and use this in the calculations," explains Rodney Baishiki of Pacific Gas and Electric Co. "Even so, we didn't have a good handle on problems like deterioration," he points out. TLWorkstation includes a more sophisticated, probabilistic method for analyzing reliability, which Baishiki describes as very impressive. This program, DESCAL, can perform three separate functions: produce a complete design loading tree for a support structure, determine the reliability of any structural component designed to carry the stresses produced by the design loading, and find the strength required for any component to guarantee a given degree of reliability.

Another spot where overconservatism is often found is transmission tower foundations. In the past few years great strides have been made in evaluating the capabilities of these foundations, according to Kennon. In an EPRI project with

*TLWorkstation is an EPRI trademark.



This Utah Power & Light Co. line was upgraded from 230 to 345 kV in six months, eliminating a 25-mi (40-km) transmission bottleneck and preserving an investment that was only 15 years old. Two extra legs and some tie-in bracing added the needed tower strength.



EPRI's TLWorkstation software is powerful and includes a sophisticated graphics capability for tower modeling. The library is also highly portable—it can be used on a variety of micro, mini, and mainframe computers.

Cornell University, researchers have evaluated data from over 800 independent foundation tests. The results of this work are currently being coded into a computer program and will become available by the end of the year as part of the TLWorkstation package.

Using computer analysis of this sort has a number of advantages. It is fast—a design and analysis process that may have taken a week can be reduced to a day. It is flexible—the ability to run repeated analyses allows considerable "what if" evaluation, something of particular value when considering upgrades. The menu-driven structure of the programs allows engineers to use them without being as intimately familiar with the computer code as they would have to be with many similar programs.

Despite the many advantages of computer analysis, full-scale testing remains of vital importance in the modification of transmission line structures. Tests at EPRI's Transmission Line Mechanical Research Facility (TLMRF), a $10.5 million facility located in Haslet, Texas, demonstrated that the simplifying assumptions built into computer analysis, when combined with normal variability, can have great effects on stresses in structures.

Although data from TLMRF tests are being used to continually improve the analytic power of TLWorkstation routines, "for any significant modification, full-scale testing will pay for itself," Kennon asserts. On the one hand, most tests find that an actual structure is considerably stronger than the computer analysis indicated. On the other hand, there are sometimes hidden problems not detected by computer analysis. As a result, tests play a major role in the economic optimization process.

Tests at TLMRF can determine the load paths, stresses, and vulnerable areas of a given design, or (more ambitiously) the facility's test pad can be used as a development laboratory. Once the characteristics of a basic structure are clearly documented, modifications can be made and tested as well. "It is much easier to be ingenious if one has a laboratory to try out ideas where failures do not cost much or endanger lives," Kennon points out. Thus, through a combination of computer analysis and full-scale testing, an engineer can decide what upgrades are possible with the assurance that they will work as expected.

The next step in the uprating or upgrading process is selection of the correct conductor. This is primarily an economic decision dependent on such factors as minimum load transfer, maximum sag, and corona effects. EPRI's transmission line optimization program (TLOP) was designed to aid in making the complex trade-offs involved. TLOP is now configured to compare options for new lines, but it can be employed to calculate conductor and structural changes that minimize the present worth of line losses and construction for various degrees of upgrading.

In the case of voltage uprating, this program allows an engineer to quickly establish the minimum conductor diameter required for such environmental constraints as audible and radio noise, the insulation rating required, and the conductor diameter that minimizes lifetime costs. One of the most common ways to increase the thermal capacity of a transmission line is to increase the conductor size. This decreases losses, but it may require significant structural modifications. When used with a model that relates structural cost to wind and ice loading, TLOP can select which conductor type and size provides the best payback.

In the past, consideration of line losses was seldom a factor in the uprating design process. Recognizing that losses have become a significant factor, TLOP explicitly adds them to estimated construction costs to determine the design with the lowest present worth for the line's lifetime.

Success story

Some upgrades are not a matter of strategic planning. One example is Arkansas Power & Light Co. (AP&L) after 30 towers collapsed like dominoes when a 500-kV line was struck by a tornado. The utility's investigation showed that the towers, designed in the early 1960s, had a serious longitudinal weakness and were failing at 50–60% of their intended design loading.

In the past the company had relied on consultants to design their transmission towers. "They would do a tower analysis, make all the decisions, and come back and tell us what they did," explains John Meeker, AP&L engineer. Over 800 towers had this design deficiency. Officials wanted to strengthen them but knew that the analysis alone would cost at least $50,000. Instead of going the usual route, they decided to obtain a TLWorkstation because "it would let us play more 'what if' games and get a design that really suited us," Meeker explains.

Using the power of this computer system, Meeker came up with a way to brace the towers. With an estimated cost of $1.5–$1.75 million to modify all the structures involved, the company decided to verify its design by testing it at the TLMRF facility. This test (conducted last November) found that the braced towers did not fail until 115% of the design loading. The modification increased tower strength by over 50%. Meeker reports that the cost of the analysis, test, and upgrade totaled $1.9 million, but the company's storm damage should be reduced by 50% over the next 15 years, saving about $20 million. Already a hundred of the towers have been upgraded.

"Although TLWorkstation is still in early stages of development, it is a good tool. And its potential is terrific," enthuses the Arkansas engineer. For the most part, it is easy to use. He continues, "Rather than having to research each line as you do in a traditional program, you can get the machine to prompt you." That means users do not have to know the program nearly as well to use it correctly as they would many older programs.

Meeker has also found that this software can save a considerable amount of time. He cites an example of designing a single-pole line. Using a TLWorkstation program tailored to this purpose (single-pole design/analysis, or POLEDA), it is possible to set up the program in 30 minutes. "Because it takes only 20–30 seconds to execute, within an hour I have something I can work with," he reports. Before, it took a full day just to fill out the worksheets and keypunch the data on computer cards.

New computer analysis tools like TLWorkstation and test facilities like TLMRF are making the job of planning transmission line upgrades easier and more reliable than ever before. Low load growth, the economic opportunities created by surplus capacity in certain regions of the country, and increased benefits from reducing losses have all enhanced industry interest in uprating and upgrading existing lines rather than building new facilities. The future is uncertain, but it is unlikely that past conditions, which so strongly favored new construction, will be repeated in the foreseeable future. Upgrading and uprating are likely to play an important and pervasive role in the years to come.

Further reading

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This article was written by David Salisbury, science writer. Technical background information was provided by Richard Kennon, Electrical Systems Division.

World Energy Conference: Total Energy Perspective

Beyond sponsoring a triennial global congress, this international organization conducts studies, issues reports, and holds forums on a broad spectrum of worldwide energy issues.

Mention the World Energy Conference (WEC) to members of the energy community and most will think of the large, international meeting held once every three years in different cities around the world. Mention the U.S. Member Committee (USC) and most will envision the organization that selects the U.S. papers presented at the triennial meetings. The process for that selection is directed from a small office in the heart of Washington, D.C.

Arranging international congresses is indeed the prominent activity of both WEC and USC, but, in fact, these organizations are engaged in many other initiatives as well. WEC and its member U.S. committee have established a number of working groups that sponsor forums and meetings on topics of international energy import; the two organizations also conduct studies and issue reports. In sum, they provide opportunities for developing and applying a broad perspective to national and international issues related to energy policy.

Just as the international organization has evolved over the years from a group primarily interested in one form of energy—electricity—to a body concerned with all forms of energy, the U.S. organization, chaired by W. Kenneth Davis, a former deputy secretary of energy and currently a consultant to Bechtel Group, Inc., is now embarked on an effort to broaden its scope of interest and to attract members from all organizations with interests in energy issues. In doing so, it is delving into new areas of concern, one of which, collaboration in energy R&D, promises to be of direct interest to EPRI.

Spanning the Globe

WEC is an organization of 79 countries around the world. WEC nations represent all political systems and all stages of economic development. The purpose of WEC is to bring representatives from all these countries together to identify issues, to exchange views, to develop an understanding of differences and commonalities in viewpoints, and to seek whatever consensus is possible in terms of recommendations and conclusions. The international headquarters of the organization is in London, and individual countries participate through national member committees.

The most prominent of WEC's activities is its triennial international congress, which attracts thousands of energy representatives from all over the world to such places as New Delhi, Munich, Vienna, and Istanbul. The 13th such international congress will get under way in October 1986 in Cannes, France, with the theme "Energy: Needs and Expectations." Its objective is to explore the underlying relationships between energy needs and global politics.

Reports for the Cannes congress are being prepared by study groups put together by the 17 permanent and ad hoc committees that serve as WEC's backbone. This extensive committee structure is designed to cover a wide range of energy problems, including such issues as resources, developing countries, energy trade, energy resource surveys, synthetic fuels, and standardization.

According to WEC, no fewer than 230 experts from 45 countries and 20 international organizations serve on these committees.

Discussing the contributions of WEC committees, Gorman Smith, the recently appointed executive director of USC, points out that the international organization needs both the congress and the committee structure to fulfill its purposes. "Most people focus on the congress," he explains. "That's the big event every three years. You need the congress to keep people interested, but the real utility of the organization comes from the committee meetings that go on between congresses. The committee work isn't glamorous and it grinds slowly, but it keeps going year after year. You need this continuity so that after a few years you can turn around and point to progress."

One such area of progress Smith can point to is the standardization of terminology and conversion factors used in the international energy arena. Through the work of its committee on energy terminology, WEC has reached agreement on certain standard definitions and conversion factors to enhance the comparability of data among countries.

"An agreement has been reached on the conversion of one measure to another," Smith explains. "For example, in terms of measuring the amount of energy involved in a certain transaction, it has been agreed that so many Btu (the nonmetric form) of energy is the equivalent of so many joules (the metric form) of energy." He adds that through the work of this committee, WEC has also published a glossary of energy terminology in eight languages.

Another of WEC's contributions has been its efforts to survey world energy resources as they now exist and to project future availability. Since the 1930s WEC has published surveys of world energy resources every six years and has revised and updated the statistical information every three years. In 1983, for the first time, WEC published surveys of individual national energy data based on a coherent system that allows comparisons among countries. Deliberations by its conservation commission formed the basis for a series of published reports on projections of future energy availability.

World Energy: Looking Ahead to 2020, published in 1978, projects energy availability to the year 2020 under reasonable economic conditions. The report is based on five separate study group reports detailing oil and gas, nuclear, coal, and renewable energy resources, and world energy demand.

Two other significant studies were also published in 1983. *Energy 2000–2020: World Prospects and Regional Stresses* examines 10 regions of the world and forecasts the outlook for each for the years 2000–2020 in terms of population, GNP, energy consumption, energy supply, energy production, and interregional energy trade. *Oil Substitution: World Outlook to 2020* focuses on what would happen to a country making the transition from an oil-based economy to one more heavily reliant on alternative energy sources. The report not only evaluates the possibilities for substituting other resources for oil in the industrial, commercial, residential, transportation, and electricity generating sectors of the energy economy, but it also analyzes the technical, economic, institutional, and environmental factors that would influence the rate at which this transitional process might come about.

Another contribution of WEC has been in the area of improving the availability of thermal generating plants. In WEC's early days, according to Smith, it was the industrialized countries that exchanged information on ways to increase the availability of power plants. "Initially, the idea was 'let's trade experiences on how we can get more availability out of our plants, because if we can get better efficiency, we won't have to build as many plants.' "

The picture changed, however, after World War II. Emphasis shifted from trading knowledge between industrialized nations to an effort to aid developing nations, which now account for over 50% of WEC's membership. "These countries found that they didn't have the technical know-how and experience they needed to operate thermal generating plants successfully and efficiently," says Smith. "So it has become a major effort of WEC, through its committee on the availability of thermal generating plants, to transfer the knowledge, experience, and skills to these developing nations."

Utility Orientation

WEC traces its origins to 1924, when 2000 electric power engineers representing 24 nations met in London to provide a forum for exchanging ideas on electric power issues. At that time the organization was called the World Power Conference; until the late 1950s, it was composed of electric utility engineers and executives who focused primarily on electric power topics.

In the late 1950s and early 1960s, however, primarily at the instigation of Walker L. Cisler of Detroit Edison Co., the organization moved to broaden its scope so that it could better deal with the growing number of energy resources and applications issues.

"Long before energy hit the headlines, the conference decided to expand its scope, realizing that electricity could not be isolated from its interaction with other energy forms," Smith comments. "The group had enough vision to say that it ought to encompass all energy sources and uses. And that's what it did."

Therefore, the organization officially changed its name in 1968 to the World

Energy Conference and, according to an announcement issued by its international headquarters, "reaffirmed its leadership as the sole, international organization dealing with all forms of energy and including all the major countries of the world."

The strong utility orientation of the international organization has been reflected in USC, which also traces its origins back to that first meeting in 1924. And just as WEC expanded its scope of interest by encompassing all other energy forms, USC is now attempting to enlarge its perspective and to achieve a more broadly representative membership base. Its 100 members are both public and private U.S. energy organizations, organized into seven categories: professional societies; trade associations; government; energy-related companies; manufacturing, engineering, and research firms; education and information groups; and legal, accounting, public relations, and other professional service establishments.

Electric utility concerns are strongly represented within this membership. Each of the three major utility trade associations—the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association—is a member, as are 19 individual utilities and other such related organizations as the Atomic Industrial Forum. EPRI is a member in the research category. Among the government member organizations concerned with electric power are the Rural Electrification Administration, the Tennessee Valley Authority, the Bonneville Power Administration, and the National Association of Regulatory Utility Commissioners. "The principal base of our membership is electric; and among the existing members, the electrics are the most active," states Smith.

Not that USC in any way wants to discourage this participation. Smith would, in fact, like to recruit more individual utility members to ensure that the full range of views in the diverse utility industry is well-represented before the committee. By the same token, USC leadership has embarked on an effort to seek greater participation from the nonelectric sectors of the energy economy.

"Participation will give the nonelectrics an opportunity to ensure that the membership of USC is more nearly representative of the U.S. energy sector," he states. "They'll have the chance to voice their opinions about what other energy issues should be addressed by the committee." For the already strongly represented electric power sector and for the organization as a whole, expanded participation will bring a greater strength and credibility to the product of the organization.

"It isn't perfectly balanced yet," Smith acknowledges, "but someone from every energy discipline is in our organization. As I said, this gives us more credibility when we make a recommendation, come out with a study, or pass a resolution."

Smith sees this product as a potentially important input into energy policy formulation. National energy policymakers are interested in this input, and Smith points, for example, to a statement issued by Secretary of Energy John Herrington this spring in which the secretary said that USC's exchanges of information and ideas "provide valuable guidance to this nation's energy policies and practices."

Smith stresses, however, that the organization as a whole does not seek an advocacy role and that it does not necessarily look for total consensus from its members on a particular issue.

"We're not necessarily trying to develop a position that a majority of the members can go along with," he explains. "What we're trying to do is to bring together a reasonably representative segment of the total energy sector, have these people consider an issue, and then develop what consensus we can. Equally important, where we cannot reach a consensus, we want to explore and develop the different viewpoints so we can give a succinct statement explaining the reasons behind these disagreements. Then we present our findings and expect people to make up their own minds."

Committee Activity

Like the international parent organization, USC conducts its work through committees, of which there are six: utilities, protection of the environment, economic analysis of energy systems, synthetic fuels, energy R&D collaboration, and energy trade issues. The committees are made up of 20 to 25 members who meet, hold forums and discussions, and may pass resolutions and draft reports. Smith explains that although USC as a whole does not advocate a particular issue, its individual committees may do so.

"If a specific committee chooses to make a statement that something ought to happen, that's fine. If it can get consensus from its members, we can put out a resolution. But it's the individual committee speaking, not USC as a whole."

Such was the case this past May when the synthetic fuels committee issued a resolution supporting the U.S. synthetic fuels program on a modest scale. The resolution was the result of study and a report written by the synfuels committee that Smith points to as an example of the kind of action that other committees could be taking on a more consistent basis. He feels that USC as a whole has yet to reach its potential and has launched a series of initiatives for the organization that will better enable it to do so.

For example, he believes strongly that the results of the various committee deliberations are not consistently communicated to a wider audience, and his goal is to encourage the committees to keep records of their deliberations and to develop these records into reports to be distributed first to the membership and then to key leaders and policymakers. The reports might even be published if, for example, interest in the subject matter is high or the quality of the report is of particular merit.

Smith began publishing a newsletter this spring in a further attempt to communicate the activities of the organization and will be issuing it quarterly to the membership, to the press, and to other interested parties. He is also encouraging the committees to meet more frequently (at least four times a year, if possible) and is attempting to effect a better mesh between USC and its international parent organization.

In addition to screening papers from the United States and presenting them to the international congresses, USC interacts with WEC by providing representatives to work on each of WEC's international committees. Smith is in the process of developing the machinery to allow the U.S. members of these committees to better represent the total perspective of the U.S. member organization as they carry out their duties.

"We need to and will organize a number of steering committees to assist and guide the representatives to these various WEC committees and to make sure that the views they reflect to the international bodies are indeed the views of the entire U.S. committee."

The steering committees would be composed of 10 or 12 members, with representatives from each of the USC membership categories. A steering committee would be formed to correspond to each of the international committees, and its role would be to develop, through discussions, USC's perspective on a given issue and then to guide the U.S. representative in his or her participation in the international body.

Smith concedes that such initiatives as the communication effort and the steering committees will require more active participation from USC members. "Our greatest opportunity and our greatest weakness lie in this area," he has noted in communication to the membership. "At present we have far more opportunity to provide our views to policymakers than we have people who are willing to serve on committees and develop and prepare those views."

He believes, however, that the interest and the participation will be forthcoming as current and prospective members realize the intrinsic value of the organization to themselves and to the energy community as a whole.

R&D Initiative

One other new initiative that excites Smith and that will be of particular interest to EPRI is the formation of a new committee on energy R&D collaboration. Organization meetings for the committee took place late this summer, and it is still very much in the formative stages.

"The idea will be to try to examine the collaborative efforts on energy R&D between the government and the private sector. In picking out the successes and failures, we will examine why one particular arrangement worked while another did not. We'll try to learn some lessons from the experience," Smith explains, "and then issue a paper. The paper's principal thrust will not be what kind of research we should be doing, but rather, how the private and public sectors should collaborate to get the most research out of the limited dollars that will be available."

This is a matter of procedure or methodology, rather than of substance. For example, Smith expects that the committee will be looking into such areas as the funding and management of research projects. One option that might be explored could be providing full funding to a project at its inception, rather than funding it year by year as it progresses.

It is difficult to fund a consistent research project when changes occur midstream through the WEC review process, he explains. Rather, he suggests, project sponsors might fare better if a set amount of money for their research is appropriated in the beginning. Although that would be all they would get, they could at least count on having that amount and plan accordingly.

The scope of the R&D committee is so large that it was broken into subcommittees according to the type of energy source: nuclear, coal, oil and shale, gas, electricity, and renewables. Smith is seeking members for these subcommittees, stressing that he will be looking for representatives from each of the membership categories. In this way he can develop a perspective that reflects the views of the entire energy community.

EPRI and the Gas Research Institute will serve as two obvious models for the committee's efforts, according to Smith. "They are two examples of how an industry has been able to consolidate its resources to fund a sustained R&D program that has generated some obviously good results and, more important, has generated institutions that are reasonably stable and can conduct continuing R&D programs.

"And it's this stability that's very important," he emphasizes, "not only to an R&D organization but also to a broad membership group like the USC of the World Energy Conference. As the new USC executive director, I'm aiming for stability and growth." ■

This article was written by Marie Mastin Newman, a freelance writer specializing in energy issues.

EPRI to Analyze Data From LOFT Reactor Meltdown Test

A test facility in the Idaho desert was the site of a controlled partial core meltdown that promises to provide the nuclear community with important reactor response data.

Valuable source term and core behavior data are expected from the results of a simulated nuclear reactor accident that took place this summer at DOE's loss-of-fluid test (LOFT) reactor near Idaho Falls. EPRI, DOE, and NRC are U.S. contributors to the LOFT project, which is funded by the Organization for Economic Cooperation and Development. The OECD–LOFT consortium, composed of the United States and nine other nations, has planned and funded a testing program at the DOE test facility to investigate nuclear reactor responses to postulated accidents.

The DOE facility is the only nuclear reactor in the world for total systems simulations of PWR transients and accidents. Numerous tests have been conducted on various accident scenarios since LOFT started operating in 1976. Experimental data from the program have helped the U.S. commercial nuclear industry demonstrate excellent safety margins.

The simulated accident was the most severe fuel damage test ever conducted in a nuclear reactor, according to Romney Duffey, senior program manager of EPRI's Safety Control and Testing Program. "The test caused a partial core meltdown that released highly radioactive fission products into the reactor vessel and surrounding structures, and damaged parts of the core."

An observer at the July test, Duffey explains what took place. "Test conditions led to a gradual heat-up of an experimental fuel bundle in the reactor core. Temperatures reached nearly 3500°F (1930°C), enough to melt the fuel rod cladding, dissolve the fuel, and allow fission products to escape. The whole test sequence was highly successful. Although on a much smaller scale, the core degradation and fuel rod failure in some ways mirrored the early events at TMI."

It is this similarity to TMI that will be especially helpful to EPRI researchers. One of EPRI's main interests in the LOFT test will be to use the results to benchmark a number of its nuclear plant computer codes developed to analyze various severe accident scenarios, especially degraded core and source term events.

"Until now," says Walter Loewenstein, deputy director of EPRI's Nuclear Power Division, "many of these codes have been validated by performing retroactive analyses of events at TMI. But an operating power plant like TMI does not have the instrumentation necessary for specific and detailed points of comparison between EPRI's codes and the reactor hardware response."

Thus the value of the LOFT test lies in the special instrumentation systems installed at the test facility to measure the release, transport, and final location of fission products, and EPRI hopes that this information will help it better assess the accuracy of its predictive computer codes.

The radioactive release and transport (source term) results will also be used by the nuclear industries and by research and regulatory agencies in the United States and other sponsoring countries in reviewing licensing criteria for nuclear power plants, as well as in determining the potential for radiologic release to the environment during accidents of a similar nature. The data generated by the tests will take approximately six months to collect, and the results will then undergo about a two-year analysis by consortium researchers.

The final test was the 38th in a series conducted at LOFT. After a cooldown period of several months, the components containing the critical test data will be removed from the reactor, and facility decontamination and decommissioning is expected to begin under the auspices of DOE. The reactor is to be removed from the containment building and placed in interim storage; LOFT facilities will then be made available for other testing programs. ■

EPRI Board Increases Funding for Research in Progress

At its August meeting in Denver, Colorado, EPRI's Board of Directors authorized an additional $57.9 million to increase the spending levels of 10 ongoing research projects. The largest funding increment went to the Energy Analysis and Environment (EA&E) Division's solid-waste environmental studies, a project designed to provide data, scientific understanding, and a predictive methodology to define when and to what extent, if any, leachates at waste disposal sites should be contained to achieve environmental objectives.

Another EA&E program, the human health effects and short-term air pollutant exposures study, also received additional funds. The goal of this study, which will assess the effect of various air pollutant mixtures on the lung functions of both healthy and lung-impaired persons, is to provide the utility industry with rigorous results that can be used to advocate rational ambient air quality standards.

The Board awarded significant increases to the Coal Combustion Systems Division's Coal Cleaning Test Facility (CCTF) and to the High-Sulfur Test Center (HSTC). The additional money will enable CCTF to continue characterizing major steam coals and developing and demonstrating improved cleaning technologies that can result in savings of millions of dollars for large coal plants. The funds for HSTC will go toward the construction of a high-sulfur coal spray dryer and fabric filter, plus a revision of the scope and costs of the original design of the facility.

Two other CCS projects also received more funding. One, a study of solid particle erosion in steam turbines, is developing and demonstrating materials and methods to reduce the effects of erosion on steam turbine efficiency and maintenance, with the goal of reducing fuel and maintenance costs for a 100-MW unit. The other, the fabric filter development and optimization project, is conducting research on fabric filtration technology at the Arapahoe Test Facility to reduce baghouse capital costs and to avoid boiler derating.

The Board also increased funding for the Nuclear Power Division's study on predicting corrosion-assisted cracking in nuclear power plants and awarded more money for the Advanced Power Systems Division's coal gasification tests at Texaco pilot plants. These tests will obtain performance data on high-sulfur eastern bituminous coals.

Two Energy Management and Utilization Division projects received additional money. One is a project to develop the technologic base to support a molten carbonate fuel cell technology demonstration by 1992. The other is a project to evaluate the performance, reliability, and life of large-generation electric vehicle systems and components to determine their readiness for fleet application and future R&D needs. ■

Wind Power on the Rise, Turbine Reliability Improving

The wind turbine industry's dramatic growth over the past four years has expanded its business 10-fold, from $45 million in 1981 to $472 million in 1984. According to the recently compiled results of EPRI's 1984 wind power survey, wind turbine shipments have surged from 25 to 360 MW in the same period.

By mid 1984 more than 4000 wind turbines (with an aggregate nameplate rating of about 300 MW) had been installed in the United States. With at least as many machines currently in the planning stages, the number expected to be installed by the middle of this year is about 10,000. "Wind power technology is showing significant progress and could be a competitive option for direct utility use in the early 1990s," predicts Edgar DeMeo, manager of EPRI's solar program.

The wind power industry's rapid development in recent years has been due principally to federal and state investment incentives, tax credits that have made wind power a very attractive prospect, according to DeMeo. The industry currently includes over 70 nonutility wind power developers financed by partnerships formed to take advantage of these tax credits. Such financial incentives are not available to the utility industry, and few wind power stations are utility-owned. Federal financial incentives are scheduled to end at the close of 1985.

Although wind power stations are beginning to spread across the country, California remains the center of development because of good wind resources, favorable state tax incentives, and high energy value. California has over 95% of the total wind turbines installed for bulk power production in the United States.

Among developmental trends documented in the recent EPRI survey of 105 wind power stations (AP-3963) is a tendency toward higher-rated midrange (100–600-kW) turbines, which are potentially more cost-effective than their smaller predecessors. However, the primary remaining uncertainty for both the small and the midrange machines is their long-term reliability. Before that can be known, several years of operating experience on statistically significant numbers of machines will be necessary.

"If they prove reliable, midrange turbines could eventually penetrate the utility market sector," reports Frank Goodman, EPRI project manager. Wind turbine prices have fallen substantially in recent years, from $2000–$3000 per kilowatt in 1981 to $1000–$1500 per kilowatt in 1984. Further price declines are expected as midrange machine technology matures. Turbine quality has improved markedly over the same time period, the EPRI survey notes.

One significant trend is the increasing acceptance of foreign-manufactured wind turbines. According to the EPRI report, about one-third of the turbines installed in the United States in 1984 were manufactured abroad, a dramatic increase from 1983. Because of their reliability, Danish-made turbines in particular have gained wide market acceptance. For further information, contact Frank Goodman, EPRI project manager, Advanced Power Systems Division (415) 855-2872. ■

Guide to Commercial Cool Storage Systems Now Available

The first comprehensive guide to the design of commercial cool storage systems has just been published by EPRI. Cool storage systems are used in large buildings to shift peak-hour cooling demands to off-peak hours. Already installed in several hundred buildings in the United States and Canada, the systems can help users reduce peak-hour electricity demand and save substantially on electric bills. The shift of demand to off-peak hours is also expected to help utilities operate more efficiently.

The EPRI guide to the design of the systems contains state-of-the-art information for evaluating the cost-effectiveness of cool storage options; for selecting, configuring, and screening system alternatives; and for designing a heating, ventilating, and air conditioning (HVAC) system that incorporates cool storage. EPRI members may order the guide by requesting EPRI report EM-3891 from the Research Reports Center, P. O. Box 50490, Palo Alto, California 94303, (415) 965-4081. ■

CALENDAR

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

NOVEMBER

13–15
Symposium: Coal Pulverizers
Denver, Colorado
Contact: David Broske (415) 855-8968

14–15
2d Annual Conference: Utility Investments Risk Analysis
New Orleans, Louisiana
Contact: Stephen Chapel (415) 855-2608

20–21
7th Annual NDE–Structural Mechanics Information Meeting
Palo Alto, California
Contact: Soung-Nan Liu (415) 855-2480

20–22
Municipal Solid Waste as a Utility Fuel
Madison, Wisconsin
Contact: Charles McGowin (415) 855-2445

DECEMBER

3–4
Workshop: Generator Reliability
Scottsdale, Arizona
Contact: Dharmendra Sharma (415) 855-2302

9–11
International Conference and Exposition: Load Management
Chicago, Illinois
Contact: Veronika Rabl (415) 855-2401

10–11
Seminar: Advances in Liquid Radwaste Processing
Orlando, Florida
Contact: Patricia Robinson (415) 855-2412

FEBRUARY

2–5
3d Symposium: Integrated Environmental Control
Pittsburgh, Pennsylvania
Contact: Edward Cichanowicz (415) 855-2374

9–11
8th Annual Workshop: Radwaste
Savannah, Georgia
Contact: Patricia Robinson (415) 855-2412

12–14
Symposium: Advances in Fossil Fuel Power Plant Water Cycling
Orlando, Florida
Contact: Wayne Micheletti (415) 855-2469

25–28
6th Symposium: Transfer and Utilization of Particulate Control Technology
New Orleans, Louisiana
Contact: Ralph Altman (615) 899-0072

MARCH

18–20
Steam Turbine Blading
Los Angeles, California
Contact: Thomas McCloskey (415) 855-2655

19–21
PWR Primary Water Chemistry and Radiation Field Control
Oakland, California
Contact: Christopher Wood (415) 855-2379

TAG Helps Virginia Power Assess Alternatives

A consistent set of economic and technical guidelines for comparing engineering alternatives, the *Technical Assessment Guide* (TAG) was first developed as an internal tool to help EPRI compare R&D alternatives. TAG has since become a resource that utilities are using to evaluate technologic alternatives. The guide includes economic data, capital and operating cost estimates for utility technologies, and such technical data as heat rates at various loads, fuel requirements, and representative maintenance and forced outage rates. Although prepared on an aggregated basis and not suitable for site-specific studies, TAG data can be useful in evaluating generic alternatives for resource planning, as Virginia Power has done for the last two years. Virginia Power estimates TAG will save the company more than $160,000 in generation planning costs over the next five years. ■ *EPRI Contact: Stanley Vejtasa (415) 855-2489*

EPRI and Salt River Project Evaluate Prototype Turbine Control System

As a way of accelerating the development of mature systems for utility use, EPRI asked the Salt River Project to participate in a study evaluating a prototype combustion turbine digital control system, called the Mark IV, developed by General Electric Co. The Mark IV was designed as a fault-tolerant system to help utilities reduce the historically high rate of forced outages and other problems associated with turbine control reliability. After taking part in a design review of the Mark IV with General Electric, Arinc Research Corp., and EPRI, the Salt River Project volunteered its SanTan Unit 4 for a field test of the system's dependability. Analyses after the initial year of operation indicated that the Mark IV showed greater reliability than a functionally similar system that had seen long-term field use, and it was also able to eliminate turbine downtime because its component redundancy permitted panel repairs during turbine operation. The early involvement of the Salt River Project in EPRI's evaluation of the Mark IV meant that General Electric received valuable utility input in the design and test phases of its product, which helped produce a control system that answers the utility need for improved gas turbine reliability. In addition to the Salt River tests, ongoing EPRI research is tracking studies of Mark IV reliability growth at other utility installations. ■ *EPRI Contact: George Quentin (415) 855-2524*

California Utilities Test Urea Injection Method for NO_x Reduction

EPRI has recently awarded licenses to San Diego Gas & Electric Co. (SDG&E) and Southern California Edison Co. (SCE) to test the application of an EPRI-developed process that uses the injection of urea into utility boilers to reduce their levels of nitrogen oxides (NO_x). The process offers utilities an alternative option for supplementing combustion modification techniques for meeting utility NO_x reduction goals. In this process a spray of urea and water solution is injected into the furnace, downstream of the primary combustion zone but ahead of the convective pass. When the urea solution is injected at the appropriate temperature and position within the furnace, NO_x reductions of up to 50% can be achieved. The purpose of the demonstration tests is to find the optimal location, temperature range, and mixing conditions within the boiler for the introduction of the urea. The tests are being conducted on both natural gas and residual fuel oil at SDG&E's 110-MW Encina Unit 2, with SCE participating. A nonutility licensee, Fuel Tech, Inc., has also been licensed by EPRI for commercial development and application of the urea-reduction process. ■ *Contact:*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

SONIC–ENHANCED REVERSE–GAS BAGHOUSE CLEANING

Collection efficiencies greater than 99.9% are commonly achieved in existing reverse-gas-cleaned baghouses. In some instances there may be problems with the effective removal of the collected dustcake from the fabric, resulting in unacceptably high bag weight and pressure drop. Recent experience in both pilot units and full-scale systems shows that intense sound, properly applied, can significantly improve dustcake removal and, consequently, reduce pressure drop. The use of sound with reverse gas has reduced pressure drop 50–60% in plants burning low-sulfur western coal. The improvement was somewhat less (20–30%) in plants burning high-sulfur eastern coal.

Well-maintained utility baghouses generally achieve very high particulate collection efficiencies (mass collection efficiencies over 99.9%, with outlet emissions as low as 0.005 lb/10^6 Btu), clear stacks (opacities as low as 0.1%, equivalent to an in-stack visibility of over 50 mi, 80 km), and good bag life (averages of over four years). At present, more than 90% of utilities operating baghouses clean them by reverse gas. However, in reverse-gas cleaning, residual fly ash dustcakes often build up gradually on the bags over time. The dustcakes can become heavy, from 0.5 to more than 1 lb/ft^2 (2.4 to 4.9 kg/m^2), the equivalent of 50–150 lb/bag (23–68 kg), or as much as 20 times the weight of dust accumulated during a single filtering cycle. As dustcakes build on the bags, tubesheet pressure drop tends to rise slowly from initial values of approximately 3.0 to 5–7 in of water after several months of operation.

To better predict and control residual dustcake thickness and weight, and hence pressure drop, EPRI is conducting investigations to improve the reverse-gas cleaning process. Sonic enhancement appears to be a promising option, and a number of utilities are now using horns to augment reverse-gas cleaning in full-scale baghouses. However, the benefits of sonic energy can be realized only if horns are properly applied. For example, their power must be adequate and concentrated in the correct frequency range, and well distributed throughout the baghouse compartment. Observations of the action of sonic energy in fracturing and dislodging dustcakes from fabric surfaces suggest that the principal mechanism is vibration of the fabric and dustcake. Evidently, the rapid movement back and forth stresses the cohesive forces that bind the dustcake together.

Utilities generally use pneumatic, diaphragm-operated horns because such instruments are durable, uncomplicated, and capable of producing sounds of the required frequency and intensity. The capital cost of these types of horns is less than 1% of total baghouse cost, and operating costs are minimal. Typical horns have four critical components: air supply system, housing, diaphragm, and bell. Their power and frequency depend largely on three factors: air pressure, diaphragm stiffness, and bell geometry.

A large source of compressed air is required to provide the 40–90 ft^3/min (0.19–0.42 dm^3/s) at 40–90 psig (276–620 kPa) pressure most commercial horns demand. If several horns are to be operated simultaneously, careful design of the compressor, piping, and air receiver and drying systems is necessary to ensure adequate air pressure and flow rates. The air supply system should be designed to operate all the horns in one compartment for approximately 30 s. Because excessive pressure losses can occur in the air supply lines, the distribution system should have properly sized piping.

The two primary variables governing a horn's capability for bag cleaning are frequency and power. Manufacturers usually rate their horns in terms of their fundamental frequencies (in Hz). The fundamental is the lowest frequency at which any device or system will resonate. Optimal bag-cleaning acoustic frequencies might be a bag-resonant frequency or another frequency that favorably interacts with the bag and dustcake system to promote dustcake removal. Horn power is a more complex concept and must be carefully defined. There are two conventional methods for expressing the magnitude of sound. The first, sound pressure, is the root-mean-square average of the oscillatory deviations from the mean (atmospheric) pressure. Units for sound pressure are pascals (Pa). The second, sound pressure level (SPL), is the logarithmic expression of relative pressure defined in units of decibels (dB) and can be calculated from the following expression.

$$\text{SPL (dB)} = 10 \log_{10}\left(\frac{p}{p_o}\right)^2 = 20 \log_{10}\left(\frac{p}{p_o}\right)$$

where p is the sound pressure being measured, and p_o is the reference sound pressure, usually 20 μPa.

Table 1 shows examples of the relationship between sound pressure level and sound pressure. Although the difference between 120 and 140 dB may seem small, it actually corresponds to a factor of 100 in power avail-

Table 1
ACOUSTIC PARAMETERS

Sound Pressure (Pa)	Sound Pressure Level (dB)*
20,000	180
2,000	160
200	140
20	120
2	100
0.2	80
0.02	60
0.002	40
0.0002	20
0.00002	0

*The reference sound pressure is 20 μPa.

able for cleaning. Consequently, sound pressure level can be easily misinterpreted, and sound pressure gives a clearer picture of available power. Further, a horn's mechanical effects in bag cleaning are best characterized by sound pressure because the local acceleration of a loaded fabric is directly related to sound pressure.

Horn characterization and effectiveness

Several diaphragm-operated pneumatic horns are commercially available, but selection may not be straightforward. A choice made strictly on the basis of fundamental frequency and integrated power output, usually specified by the manufacturer, may not produce the best result.

To characterize the optimal frequency ranges and power requirements of horns in reverse-gas cleaning, Southern Research Institute tested five commercial horns at the fabric filter pilot plant (FFPP) in EPRI's Arapahoe Test Facility. These horns had rated total sound pressures, integrated over all frequencies, in the range of 100–200 Pa at a distance of 1 m from the bell (sound pressure levels of 140 dB) and rated fundamental frequencies of 150, 200, 250, 360, and 550 Hz, respectively (manufacturer ratings).

Figure 1 presents spectra of sound pressure versus frequency for two hypothetical cases and for the horns tested. The hypothetical cases in Figure 1a illustrate principal features of acoustic frequency and sound pressure spectra. Horn 1 (color) has a fundamental frequency of 250 Hz and harmonics at 500 and 800 Hz. In this particular case, the greatest contribution to the total sound pressure is concentrated at or near the second harmonic and not the fundamental frequency. Therefore, the specification of this horn's total power and fundamental frequency would not convey its true performance. In contrast, the majority of horn 2's sound pressure components are found at or near the fundamental frequency. In this case, the specification of total power and fundamental frequency is a more reasonable representation of horn performance.

Figures 1b through 1f show a wide range of sound pressure versus frequency spectra for the five horns tested. Some horns have a substantial fraction of their total power concentrated at their fundamental frequencies. Others have harmonics higher in power than their fundamental frequencies, with total power distributed over a wide range of frequencies. Given these findings, it is apparent that fundamental frequency and total power are not accurate measures of a horn's performance. A more appropriate measure would be a definition of horn performance in terms of a power-weighted mean frequency (PWMF)—the geometric average of the power distribution across the frequency spectrum—and a standard deviation indicating the degree to which the total power is concentrated near the PWMF. EPRI and Southern Research are currently developing a classification procedure for horn performance based on the PWMF, which should be available by November 1, 1985.

Testing at FFPP demonstrated that high sound pressures in the low-frequency range below approximately 250–300 Hz, not integrated or total power, are most effective for good bag cleaning. At higher frequencies, increasingly higher power levels are required for good cleaning. At very low frequencies, reso-

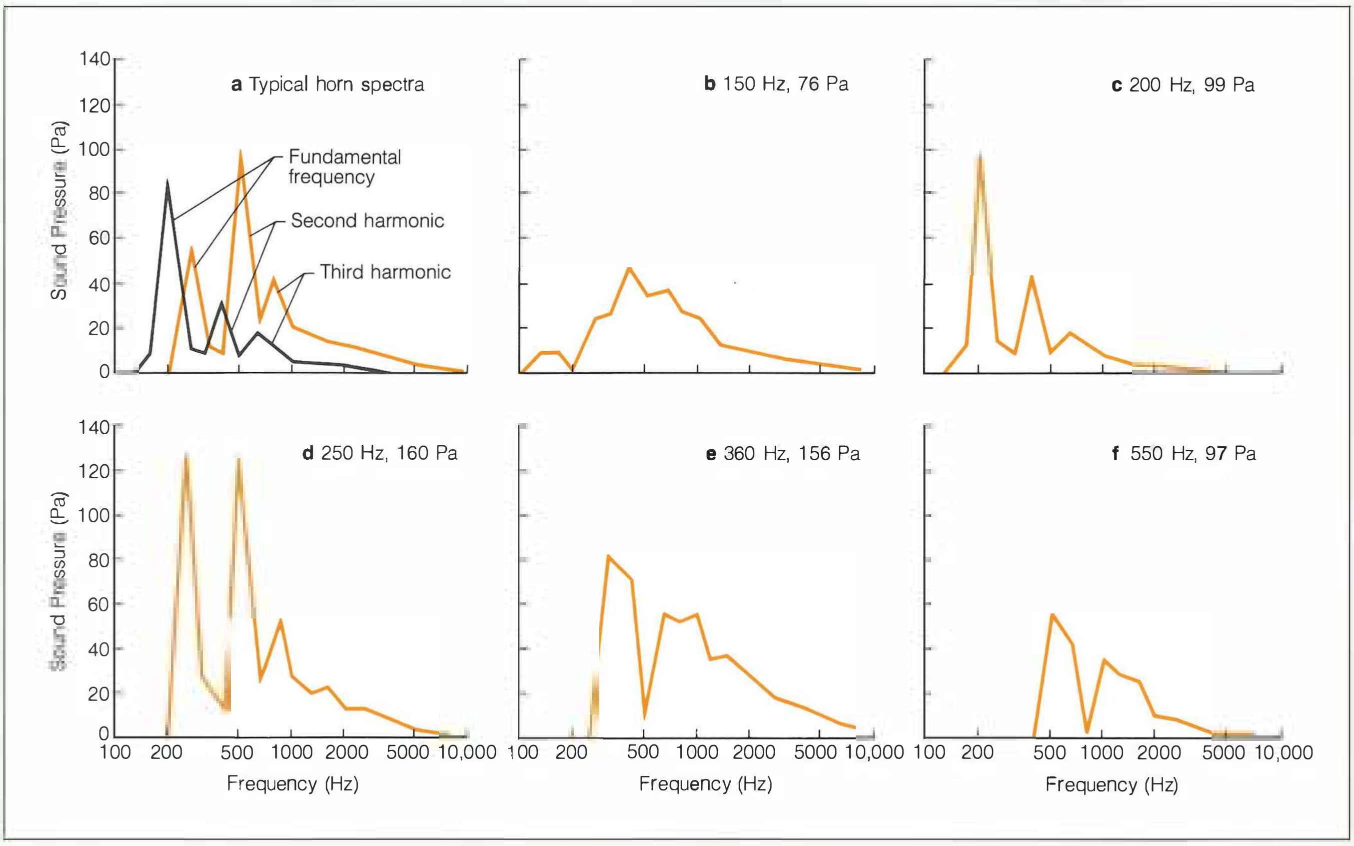
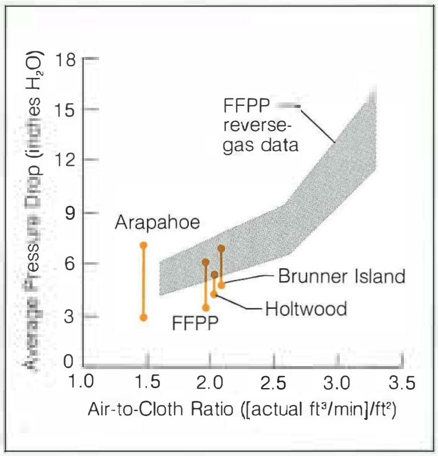


Figure 1 Sound pressure versus frequency spectra for (**a**) two hypothetical cases—horn 1, color; horn 2, black—and (**b–f**) the five commercial horns tested at the FFPP. Each commercial horn is labeled by its rated fundamental frequency and sound pressure (total, integrated power). These horns were selected for their availability and rated power and frequency spectra and are not necessarily representative of all options.

Figure 2 In studies at three full-scale baghouses and the FFPP, the use of horns (200 Hz, 99 Pa) with reverse-gas bag cleaning was found to reduce average tubesheet pressure drop. In each case the lower data point indicates the result when sonic enhancement was added. For comparison, FFPP data on reverse-gas cleaning alone are also given.



nances and practical concerns about damage to baghouse structure limit horn application. Results also show that combined sonic enhancement and reverse gas are uniformly more effective in bag cleaning than either method used alone and that horns should be operated for a 15–30-s interval during the normal reverse-gas cleaning for best effect.

To confirm data collected at FFPP, EPRI sponsored studies by Southern Research at full-scale baghouses filtering fly ash from both low- and high-sulfur coal (RP1129-8). Figure 2 shows how the use of horns improved pressure drop at the pilot plant and at three full-scale units: Pennsylvania Power and Light Co.'s Holtwood Unit 17 and Brunner Island Unit 1, and Public Service Co. of Colorado's Arapahoe Unit 3. The utilities retrofit these three baghouses with horns in an attempt to reduce high pressure drop and heavy residual dustcake weight. The figure shows results as average tubesheet pressure drop versus air-to-cloth ratio and compares the data with FFPP data for reverse-gas cleaning alone. The sonic cleaning data (all obtained with horns having a fundamental frequency of 200 Hz and a total sound pressure of 99 Pa, similar to Figure 1c) indicate widely varying improvements in pressure drop. For the baghouses filtering fly ash from low-sulfur western coal (Arapahoe Unit 3 and FFPP), the horns reduced pressure drop (and dustcake weight) by 50–60%. Horns in baghouses filtering fly ash from high-sulfur eastern coals (Brunner Island and Holtwood) reduced pressure drop (and dustcake weight) by 20–30%. These results indicate that horn effectiveness is fly ash dependent.

To determine how horn frequency and power affect dustcake removal from bags filtering different fly ash types, researchers conducted additional laboratory and full-scale parametric studies. These studies showed that although the best frequency range for all bag cleaning was similar (below 250–300 Hz), fabric with high-sulfur coal fly ash required substantially more acoustic power to remove equivalent amounts of dust than did bags filtering low-sulfur-coal fly ash (Figure 3). This phenomenon may be attributed to the fact that high-sulfur-coal fly ash is more adhesive and cohesive than that of low-sulfur coal. For example, bags filtering low-sulfur-coal fly ash required approximately 80 Pa for maximum cleaning; high-sulfur-coal bags required more than 160 Pa for similar results.

Other baghouse design and operating conditions may also influence horn effectiveness. The size and configuration of baghouse compartments can play an important role in the bag-cleaning effectiveness of horns. The coupling of horns and interactions with baghouse compartment structures is complex; trial and error currently determines the optimal horn number and location for good spatial distribution of energy. Fabric design and baghouse compartment cleaning sequence are other variables potentially affecting performance.

Horn installation and operation

Horns are usually mounted at the top of a baghouse compartment at evenly spaced positions to distribute the sound as uniformly as possible. Baghouses usually have enough space above the bag supports for horn installation, and directing the horns downward allows the sound to follow the vertical channels between the bags. The effects of sounds from two or more sources do not add up directly because of the nature of sound waves. In addition, the reflection of sound waves from solid surfaces and the absorption of waves by compartment insulation (which should be lagged to minimize absorption) or by the bags themselves can interfere with horn effectiveness. Predicting sound intensity at any point in a compartment is therefore very complicated.

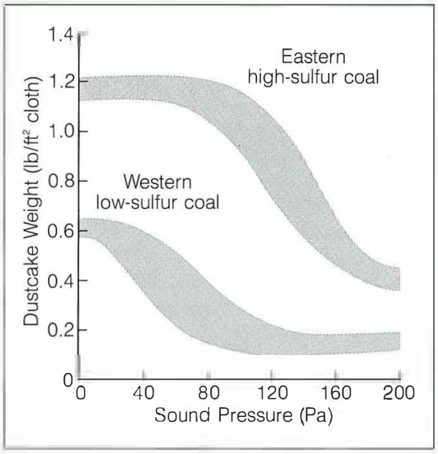


Figure 3 Test results on sonic-enhanced reverse-gas cleaning (200-Hz, 99-Pa horns) show that more acoustic power is required to remove dustcakes from bags filtering high-sulfur-coal fly ash than from those filtering low-sulfur-coal fly ash.

The most practical way to ensure that the power of candidate horns is adequate and well distributed before outfitting an entire baghouse is to install a set of horns in only one compartment and measure horn power throughout the compartment with a sound pressure level meter. Utilities may wish to evaluate more than one type of horn with the appropriate frequency and power specifications to ensure the best possible arrangement.

Two potential issues of concern in augmenting reverse-gas cleaning with horns are possible reduced bag life and increased outlet particulate emissions. Data collected over a two-year period from full-scale baghouses and FFPP indicate that horns have had no measurable effect on bag life. To investigate the possible increase in particulate emissions, researchers collected data on inlet and outlet mass concentrations at FFPP. One compartment was cleaned by reverse gas while simultaneously using a horn with a 200-Hz fundamental frequency, and another was cleaned by reverse gas only. The average inlet concentrations for each compartment was approximately 3.3 gr/ft^3.

Average mass concentration at the outlet of the reverse-gas-cleaned compartment during the test period was 2.9×10^{-4} gr/ft^3, which resulted in an overall compartment penetration of 0.009% (99.991% efficiency). For the reverse-gas–sonic-cleaned compartment, outlet emissions rose from 7.4×10^{-4} to 14.5×10^{-4} gr/ft^3 immediately after the horn was actuated. The concentration fell to 3.9×10^{-4} gr/ft^3 by the end of the 20-day test period. Sonic cleaning appears to have had a small effect on outlet emissions when first used, but then an equilibrium was established with emissions nearly equal to those achieved with reverse-gas cleaning alone.

The fact that emissions were similar for the two cleaning methods after several days indicates that sonic-enhanced reverse-gas cleaning should not significantly increase emissions. However, because dustcakes take many months to build up in baghouses, EPRI plans more-detailed, longer-term tests. Sonic-cleaning guidelines will be available this fall for use by utilities and others interested in applying sonic cleaning to reverse-gas-cleaned baghouses. *Project Manager: Robert C. Carr*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

In situ NDE testing of generator retaining rings

Generator retaining rings are subject to very high mechanical stresses. To safely withstand these stresses, rings are made with special nonmagnetic alloy materials. However, in environments of high stress and moisture, these special alloys are highly susceptible to intergranular stress corrosion cracking (IGSCC). Such cracks have been identified as the primary cause in most of the 37 known ring failures (EPRI EL-3209).

EPRI spearheaded research into new alloy materials that reduce retaining ring vulnerability to stress corrosion (EL-2674, EL-3169, and CS-1808), as well as research on manufacturing techniques. Today, new or improved composition alloys are available, and the production of a life-size ring with these alloys has been demonstrated.

Although new, stress corrosion–resistant materials are available, the retaining rings of existing generators are potential victims of IGSCC. The purpose of this study is to identify a reliable means of inspecting retaining rings without generator rotor disassembly.

Periodic inspections of the rings are usually limited to visual and dye penetrant tests of the outer surface of the ring during generator overhauls. To inspect the shrink-fit area and the inner surface of the ring, it is necessary to remove the rotor from the stator, take off the retaining rings, inspect them, shrink them back on, and reassemble the machine. To eliminate this costly and time-consuming process, attempts have been made to provide methods of inspecting the retaining rings while the rotor is in the machine.

Several domestic and foreign generator manufacturers have reported the use of eddy-current and ultrasonic inspection techniques. However, a complete and reliable crack detection method and its suitability for inspection of any retaining ring in situ have not yet been fully demonstrated. An inspection method that can be applied to any type of retaining ring without a design-specific detailed description of the geometry of the inner surface of the ring is not commercially available in the United States at the present time.

A project has been designed to survey and evaluate the status of automated or semi-automated NDE techniques for shrunk-on generator retaining rings (RP2719). In the first phase of the project, the contractor, J. A. Jones Applied Research Co., will review existing domestic and foreign NDE practices. Where possible, the contractor will observe the actual examination of retaining rings and collect any available data on a particular technique's capability to detect defects and measure the flaw size.

The second phase of the project involves independent verification of the examination techniques. The manufacturers and/or inspection agencies selected in the first phase of the project will be invited to examine the cracked ring samples at the EPRI NDE Center. Techniques will be evaluated for the following criteria.

- Detectability of flaws as a function of flaw size and location
- Capability for measuring flaw size
- Test repeatability
- Treatment of false indications

The final phase of the project will include development of a plan to demonstrate procedures and inspection system and personnel performance in blind tests. Implementation of this plan should help utilities assess the qualifications of personnel, procedures, and equipment used to examine retaining rings. *Project Manager: Jan Stein*

Torsional fatigue life and crack growth in turbine generator shafts

Electrical disturbances in transmission networks can cause severe damage or even failure of large turbine generator shafts. These disturbances arise from many sources, including electrical oscillations in long transmission lines or line faults. In addition to possible shaft failure, the oscillations of electrical disturbances can cause couplings to slip, coupling bolts to gall, and general overall vibration levels to increase. Such damage and failure can result in unplanned outages for maintenance to machine distorted bolt holes or rebalance the shaft. The expense to the utility is often quite high. In addition to the cost of the shaft, unexpected and necessarily lengthy outages may cost over $500,000 a day, primarily in replacement power costs. Consequently, avoiding such unplanned outages is in a utility's best interest.

As a result of two shaft failures in 1970 and 1971, EPRI funded a research project with the General Electric Co. to develop a methodology for predicting cumulative damage in large turbine generator shafts that results from transmission system disturbances (RP1531-1). This methodology has been developed and is available from the Electric Power Software Center as the computer program FATIGUE. Currently, the damage methodology is incorporated in the torsional vibration monitoring system developed by EPRI under RP1746 and is also being used separately by utilities to compute shaft life expenditure. The accumulation of such data permits a utility to decide in advance whether a shaft has to be replaced, thereby avoiding costly, unscheduled shaft replacement, extensive machine damage, and lengthy outages.

The torsional failure process consists of several stages: crack initiation, crack propagation, and final fracture. The methodology is based on predicting the number of cycles to crack initiation. Such cracks are much smaller than the critical crack sizes that would result in immediate fracture. Consequently, a crack can continue to propagate in a stable manner under additional combined torsional and bending loading. Eventually, the crack will reach a critical length, at which time it can be driven rapidly to failure solely by bending stresses at a rate of one cycle per revolution. The once-per-revolution bending stresses result from rotor gravity sag and can be enhanced by misalignment of the coupling shaft sections.

Recognizing that stable cracks can propagate significantly beyond crack initiation, EPRI funded an extension to RP1531-1 with General Electric. The objective was to collect fatigue crack growth rate data and, by elastic-plastic fracture mechanics analysis, develop a methodology for predicting the applied cycles or operating time required for the crack to grow from its initial size to a specified critical size. Data generated will allow estimation of the predicted crack size, the critical length to which the crack could be allowed to grow, and the rate of fatigue crack growth under applied torsional transients. With this information, the utility would realize the following benefits.

- Safe crack inspection intervals can be set for continued operation.

- The risk associated with failure to detect cracks by means of a rotor inspection program can be assessed.

- The residual life can be estimated after machining away a detected crack by assuming the existence of a postulated but undetected crack.

- The residual fatigue crack growth life of a shaft with bending stresses above the design value can be estimated.

The extended-life methodology has been incorporated into the FATIGUE computer program. This revised version of the program will soon be available from the Electric Power Software Center. It provides utilities with a means of extending the availability of large turbine generator shafts with greater confidence. The updated damage or crack extension prediction provides a means for determining whether a shaft needs inspection or can be run safely to its next scheduled maintenance outage. By identifying the need for potential work or replacement, utilities can make sure they have the proper parts and equipment in advance of a scheduled outage. Such advanced warning can minimize the overall cost of a projected outage and can also provide additional information for planning future generation equipment costs. *Project Manager: D. K. Sharma*

UNDERGROUND TRANSMISSION

Waltz Mill Cable Test Facility

A project initiated in 1972 and completed in 1979 successfully developed a 765-kV low-loss prototype cable featuring a new hybrid insulation (RP7812). Initial materials analysis emphasized development of an all-synthetic insulation. However, difficulties in materials costs and tape/impregnant compatibility of synthetics made a three-part laminate construction of paper, polypropylene film, and paper (PPP) promising. This combination exhibited synergistic benefits: the best mechanical and electrical properties of traditional high-voltage cellulose paper and the low-loss, low-dielectric-constant aspects of the polypropylene film.

The combination of PPP with a polybutene impregnant resulted in exceptional stability, low losses, and high ac and impulse/surge breakdown levels, exceeding expectations. The prototype cable system was installed at the Waltz Mill Cable Test Facility (RP7801) in 1981 and recently successfully completed a 27-month life test program.

The Waltz Mill test program on this 765-kV system included both cyclic and continuous loading at various temperatures up to 105°C and various applied voltages up to 137% of the rated line-to-neutral voltage (Figure 1). The calculated aging effect of this 27-month test is at least 40 years and could be more than 150 years, depending on the voltage and temperature aging coefficients chosen.

The results over the test program show exceptional stability and consistency and a favorable decrease in dissipation factor over the 27 months, including the potheads, PPP

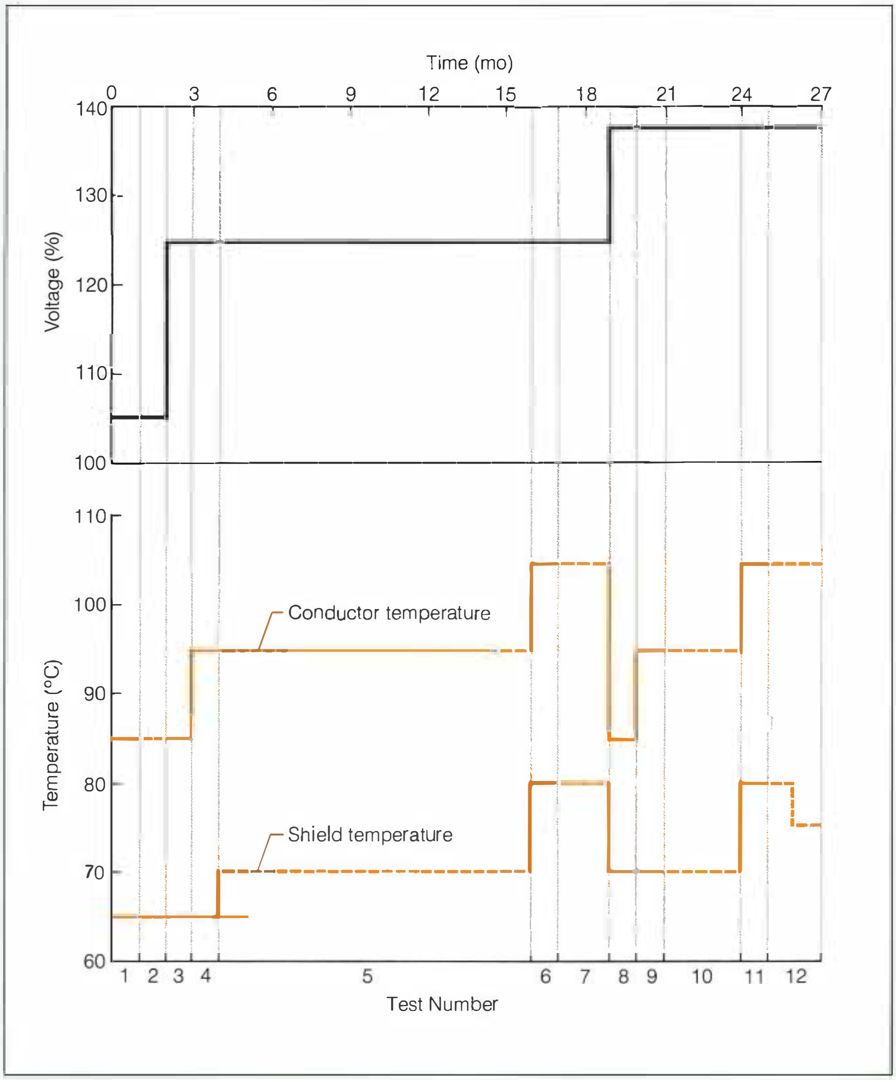


Figure 1 In a 27-month, 12-test program that simulated more than 40 years of aging, a 765-kV high-pressure, oil-filled, PPP-insulated underground cable was subjected to the voltages and temperatures shown here. The current loading was continuous in some tests (solid color lines); in others (dashed lines), it was cyclic—16 hours on, 32 hours off. The three test voltages were 800/462 kV, 956/552 kV, and 1052/608 kV.

splices, and cable runs. Since the beginning of these tests, smaller joints, operating at much higher stresses, have been developed for PPP cable systems. EPRI is considering follow-on tests to evaluate the newer design joints. *Project Manager: John Shimshock*

Thermomechanical bending of pipe-type cables

Power Technologies, Inc., has completed an investigation of the thermomechanical bending phenomenon (TMB) in underground transmission pipe-type cables (RP7873). The final report is now being prepared.

More than 90 samples of cables were tested in this lengthy project, which covered a wide range of variables thought to affect the dynamic performance of this cable's laminated structure. Investigators explored such variables as the ratio of pipe diameter to cable diameter, taping tensions, conductor lay length, taping pattern, and taping angle.

To bracket a particular variable, researchers constructed and tested cables with extreme parameters. For example, they adjusted taping tensions so that both a very soft cable and an extremely hard cable could be compared with a "normal" cable. In addition, today's cable design, called optimized construction (built with variable width tapes to pass a hot impulse test), was compared with older designs taped in uniform widths. The comparison proved very interesting, as the tentative conclusions below show.

Project personnel designed special test equipment in various configurations and used it to simulate 40 or more years of daily bend (load) cycles. The culmination of this equipment design and effort was the introduction of a small bending machine that uses only a short single-conductor evaluation sample.

Developments and tentative findings are as follows.

▫ A simple, repeatable single-conductor test for screening future designs has been developed.

▫ An optimized-construction cable tested for 30,000 cycles (the equivalent of 82 years) at a radius of 45 in (114 cm) showed no TMB damage.

▫ A 1-in (2.5-cm) paper-throughout cable developed softspots after a few cycles, and one failed after 700 cycles.

▫ Softspots tend to develop near points of skidwire wear.

▫ Even after a softspot has started to develop, the severity may not increase over thousands of cycles.

▫ Optimized-construction, short-conductor-lay cable showed no improvement over optimized-construction cable.

▫ High-tension cable construction does not test as well as optimized-construction cable.

The full significance of these developments and findings is still being assessed during preparation of the final report. The most heartening test result, however, is the fact that cable constructions in current use are highly resistant to TMB damage, even when subjected to levels of movement considered implausible for well-designed installations and when cycled well in excess of a 40-year life equivalent. *Project Manager: John Shimshock*

TRANSMISSION SUBSTATIONS

Maintenance and handling of perchloroethylene-filled electrical equipment

Because of the accelerating need to remove PCB equipment from many locations, EPRI has been sponsoring research on the use of nonflammable replacement fluids in transformers and capacitors. Tetrachloroethylene (perchloroethylene) is being considered as a nonflammable substitute for PCBs. Its use may present different problems from those encountered in the use of PCBs and other less volatile insulating fluids. EPRI has a number of transformer projects; among them are a power transformer with two-phase cooling (RP1499-2, -3) and arc by-products of tetrachloroethylene (RP1499-4, -5). This project (RP1499-6) supplements the above ongoing work; it provides information on handling equipment that resulted from the earlier developments and also for handling commercial tetrachloroethylene-filled equipment.

The first task in the project was a literature search to determine significant electrical, thermal, chemical, physical, and toxicological properties of tetrachloroethylene, as well as relevant handling requisites for tetrachloroethylene and the regulations concerning handling promulgated by OSHA, TSCA, and EPA. Results of this search were then integrated into a suggested program for perchloroethylene management. The program covers organization, operation and equipment management, information management, fluid management, spills, and health and safety.

Although tetrachloroethylene is one of several fluids considered as a replacement for PCBs in transformers, its high solvency will probably prevent its being recommended for retrofilling existing transformers unless all transformer components are known to be compatible with the fluid. Tetrachloroethylene also differs from common transformer fluids in its volatility; thus it requires attention because it evaporates readily after a spill (sometimes, simplifying cleanup). It has been used for many years as the major solvent in the dry-cleaning industry and in degreasing metal parts; therefore there is a great deal of experience and published information available from these industries. *Project Manager: Gilbert Addis*

Digital HVDC converter control system

The microprocessor has revolutionized control systems because it is so inexpensive and powerful. The control of high-voltage dc converter stations is, however, so demanding that even the most powerful of the available microprocessors has problems meeting the control needs. However, experts recognized that digital techniques used for converter controls could perform better than analog techniques, and in 1980 EPRI initiated a project with General Electric to develop such a control system (RP1942).

The digital converter controller was required not only to handle the valve firing commands for a 12-pulse converter unit but also to control the currents and voltages for rectifier and inverter operation. This includes controlling the commutation margin of an inverter. An Intel 8086–based microprocessor system has been built and tested on General Electric's HVDC simulator in Philadelphia. The demonstration called for the integration of the digital controller in a hybrid system because one of the converters used a conventional (analog-type) control system. The demonstration proved that the performance of a digital control system meets or exceeds the performance of the conventional system. The digital control system is also more flexible because it can be readily changed to meet new demands.

Future converter control systems are expected to be based on digital microprocessor designs. Further, possible additional performance improvements with this new technology may improve the response of HVDC converters to unbalanced ac system conditions or improve the performance under weak ac system conditions. Researchers are studying this possibility under a new research project (RP2675). *Project Manager: Stig Nilsson*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

DISCOUNT RATES IN UTILITY PLANNING

Because discount rates can affect investment decisions and the associated financial condition of companies, the selection and application of discount rates have important implications in utility planning. Financial constraints exist for all investment alternatives to the extent that the sources of financial capital require compensation for time and risk. Discount rates are simply a way of adjusting forecasts of cash flows to reflect inherent time and risk characteristics. They are a method of valuing the forecasts of cash flows associated with prospective investments and comparing one investment with others. Under RP1920 EPRI has been developing methods and information to help electric utilities incorporate financial constraints into investment planning. This report reviews work by the Investment Risk Management Program on the selection and application of discount rates for valuing uncertain cash flows and revenues.

Utility planners face a difficult task. They must choose least-cost and financially feasible technologies under high levels of uncertainty about demand, fuel prices, and regulation. The generation of electric power is highly capital-intensive (there is an investment of about $4 for every $1 of revenue). Investments in individual power generation units are large, and the economic lives of the technologies are typically long. The capital-intensive cost structure and long economic life of the technologies make the value of the investments highly sensitive to unexpected changes in such areas as electricity demand, fuel prices, and environmental regulations.

The suppliers of financial capital require compensation for taking the risks associated with utility investments. The ability to estimate the required compensation is a key element in utility investment planning. The quality of the estimates has a major effect on the ability to select desirable power generation strategies—strategies that are low in cost and financially feasible.

Early in 1981 EPRI started a small research program to develop information about financial constraints and ways the constraints can be incorporated into the utility planning process. The research has been done incrementally. It started with literature reviews and documentation of basic principles of financial economics and specific financial issues that the utility industry faces. The research has progressed to specific application of the principles to electric utility issues and to the development and extension of the methods and principles where needed. The completed tasks and associated reports are as follows.

- A review of the financial status of the industry. One report has been published—*The Electric Utility Industry's Financial Condition: An Update* (EA-2446-LD).

- A review of the principles of estimating financial risk. Two reports have been published—*Choice of Discount Rates in Utility Planning: Principles and Pitfalls* (EA-2445-LD) and *Analysis of Risky Investments for Utilities* (EA-3214).

- The development of a new methodology for estimating the financial risk of regulated investments. Two reports have been produced—*Choice of Discount Rates in Utility Planning: A Critique of Conventional Betas as Risk Indicators for Electric Utilities* (EA-3392) and *Choice of Discount Rates in Utility Planning: An Attempt to Estimate a Multifactor Model of the Cost of Equity Capital* (draft final report).

- A review and extension of the methodology for discounting revenue requirements. One report has been produced—*Choice of Discount Rates in Utility Planning: The Revenue Requirements Method* (draft final report).

In addition to completed research, two research tasks are currently under way. A case study is being conducted at Northeast Utilities on the evaluation of individual investment projects by using project-specific discount rates. The purpose of the case study is to develop a process for determining project- or program-specific discount rates. The final report will contain a primer on the theory of discount rates and will present a framework for estimating discount rates appropriate to specific investment projects.

The second current research task is the development of structural models for valuing risky cash flows. Such models are important when analyzing the potential value of alternative power generation technologies. A case study application of the models will examine alternative methods of recovering the cost of utility investments. The case study will examine relationships among cost recovery mechanisms, financial constraints, and choice of power generation technology. Among other items, the research is evaluating cost recovery mechanisms with regard to the ability to avoid rate shocks when power plants are first placed in service.

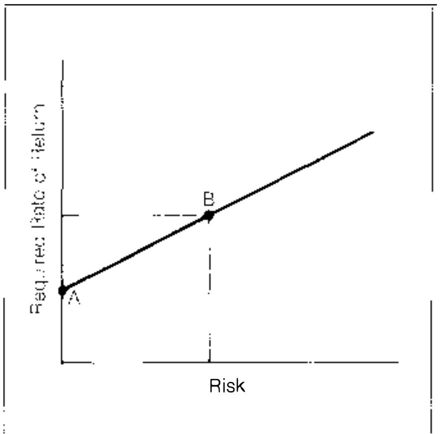
Two basic issues

EPRI's discount rate research addresses two important issues: the first concerns the role that financial theory plays in the capital budgeting process, and the second concerns the special features of risk analysis that are specific to the electric utility industry.

Capital budgeting is the process by which a corporation decides what investments to make. In essence it is a valuation process: The decision to invest requires an appraisal of prospective cash flows (assets) and capital outlays (liabilities). In the appraisal process, considerable attention is correctly focused on estimating the cost and expected cash flows associated with an investment. Less attention is usually paid to determining how financial markets will value capital outlays and cash flows. But valuation is important, and because financial theory describes how assets and liabilities are priced in competitive markets, it provides a foundation for capital budgeting procedures.

Most people are aware of developments in

Figure 1 Capital market risk-return line. As the risk of an investment rises, so does the required rate of return on the investment—or the opportunity cost of the capital. Investment *B*, which entails a degree of risk, requires a higher rate of return than investment *A*, which is risk-free.



finance that attempt to explain the relationship between risk and return in capital markets. The central idea is often depicted by a market line, which describes the trade-off between risk and the required rate of return (Figure 1). Capital budgeting procedures sometimes reflect this idea insofar as different discount rates are used to evaluate projects in lines of business having different risks.

Although the risk-return line is an important concept, it tends to obscure the fact that an investment is composed of a bundle of cash flows and that investment risk is a complex function of the way investors form and revise expectations of cash flows. Valuation of uncertain cash flows is a difficult problem and requires more than capital market theory; it requires models of investment cash flows as well.

The second important issue underlying EPRI's discount rate work is the existence of features of investment risk that are peculiar to the electric utility industry. Rate-of-return regulation leads to evaluation of investments on the basis of cost criteria rather than profit criteria. And because cost streams and profit streams have different risk characteristics, there will be systematic differences in the appropriate discount rates used to value these streams. Also, rate regulation itself affects the risk of revenue and profit streams, thereby complicating the analysis of investment profitability.

The capital budgeting problem

Financial theory recommends that managers adopt the net present value rule for capital budgeting (i.e., that they accept an investment if its net present value is greater than zero). Capital budgeting requires the valuation methods from financial theory and also models to estimate cash flows. Specifying a complete structural model for a typical investment is likely to be a formidable undertaking. Fortunately it is possible to derive some important information about investment risk by using simple cash flow models based on the principle that it is easier to solve a problem if you break it into parts.

The first step in devising simple cash flow models is the recognition that an investment is composed of a bundle of cash flows, including capital outlays, revenues, operating expenses, and taxes. Each of the cash flow streams usually spans more than one period and has a different degree of risk, and the risk can change over time. These cash flows can be valued separately by using appropriate discount rates. Specifically,

$$PV_t = PV_r - PV_e - PV_c$$

where PV_t is the value of the net cash flow stream, PV_r is the value of the revenue stream, PV_e is the value of the operating expense stream, and PV_c is the value of capital outlays. All items are expressed in terms of cash flows rather than accounting flows.

It is likely to be easier to identify appropriate risk adjustments (discount rates) for the component cash flows than for the aggregate cash flows. For example, if capital outlays are certain, they are safe and should be discounted by using a risk-free discount rate. In contrast, operating revenues for a specific investment are likely to have risk characteristics close to the risk characteristics of the demand for electricity. The discount rate for valuing the revenue stream should reflect the effects of demand uncertainty.

A key advantage of breaking the cash flows into components is that it provides some insights about the effects of cost structure on net cash flow risk. Cost structures vary among investments—that is, the relative magnitude of capital outlays, fixed operating expenses, and variable operating expenses differs among investments. Because the root causes of cash flow uncertainty affect the cost components differently, risk and appropriate discount rates vary among components. This fact allows some generalizations about the riskiness of investment projects.

Other factors being equal, net cash flow risk increases with operating leverage (the degree to which operating costs are fixed with respect to output) and decreases with capital intensity (the degree to which costs involve fixed capital investment rather than fixed or variable operating costs). The basic intuition behind these generalizations comes from the fact that revenues must first cover operating costs before they are available to compensate investors. With high operating leverage, reductions in sales are not matched by similar reductions in operating costs, and cash available for return to investment is reduced. With high capital intensity, capital costs are high relative to operating costs, and a greater proportion of revenue is available for return to investment. Figure 2 shows the impact of operating leverage

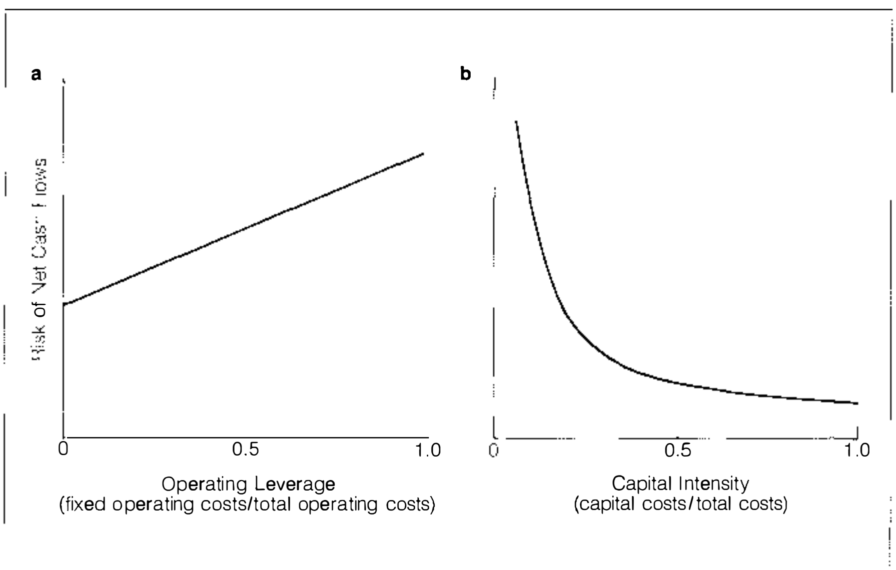


Figure 2 Effects of operating leverage (**a**) and capital intensity (**b**) on net cash flow risk. As operating leverage rises, the proportion of revenue available for return to investment decreases and risk increases. As capital intensity rises, the proportion of revenue available for return to investment increases and risk decreases.

and capital intensity on net cash flow risk for a specific and simplified example.

Capital budgeting in electric utilities

Simple models of investment cash flow have some interesting implications for analyzing cost risk and profit risk in electric utilities. With regard to cost risk, they help explain why discounting revenue requirements (total costs) by using risk-adjusted discount rates seems to give counterintuitive results. If a high discount rate is used to calculate the present value of revenue requirements, the result will be a lower present value. This result seems to indicate a more favorable investment—that is, it seems to indicate that a risky investment is better than a safe investment.

The paradox is explained by distinguishing between the risk of net cash flow streams and the risk of cost streams. Risk in the context of cost analysis differs from risk in the context of profit analysis. The risk of net cash flows increases with operating leverage. Operating leverage is created by fixed costs, and a high-operating-leverage investment should have a high discount rate. In a cost analysis, in contrast, fixed costs are safe and will have a relatively low discount rate. The risk adjustments for an investment move in opposite directions, depending on whether one is analyzing costs or profits. If a cost stream is safe, the corresponding net cash flow is risky, and vice versa.

The fact that net cash flow risk and revenue requirement risk are not the same suggests a potential for valuation errors. If the present value of revenue requirements is calculated by discounting on the basis of the cost of capital for the utility, the discounting will reflect the risk of net cash flows for the utility—not the risk of revenue requirements. Simple models of investment cash flow suggest that the risk of the operating cost stream is likely to be lower than the risk of the net cash flow stream.

Analysis of the profitability of electric utility investments is a more difficult problem. Specifically, because of rate regulation it is much more difficult to assess the risk of net cash flow streams than it is to assess the risk of cost streams. Net cash flow risk depends on revenue risk, expense risk, and the degrees to which revenues and expenses contribute to net cash flows. Valuation of net cash flows requires structural models for forecasting investment cash flows.

The models should include the following information.

- Descriptions of the relationships between investment cash flows and important underlying variables, such as fuel prices and demand
- A probability distribution for the time path of each underlying variable
- A description of the relationship between the uncertainty of the underlying variables and the compensation that investors require

Regulation is a key complicating factor here. Regulation affects the risk of utility revenues and therefore affects the risk of net cash flows. The structural models should therefore include a characterization of regulation. Developing these models is the main research task currently under way.

The above discussion of the basic issues is based on EPRI-sponsored research being conducted at Charles River Associates. Some of the material is drawn from a paper by James Read that was presented at a conference at Rutgers University in May 1985. *Project Manager: S. W. Chapel*

COAL COMBUSTION BY-PRODUCT RISK MANAGEMENT

Coal-fired power plants produce a number of solid-waste streams in the course of their operation. These coal combustion by-products are composed primarily of fly ash, bottom ash, and sludge from flue gas desulfurization. In 1980 these streams totaled about 70 million tons. Because the by-products contain low-level concentrations of such substances as arsenic, boron, and selenium, the effect of any disposal technology on groundwater quality must be carefully considered. The technologies must also be evaluated in light of the cost of disposal. For example, the use of a liner can reduce the flow of contaminants from a site into the groundwater, but a substantial increase in disposal cost will be incurred. Because the stakes are high for both cost and potential impact on groundwater, it is important that reasoned balances be made in determining the appropriate level of groundwater protection. EPRI is developing an analytic tool based on decision analysis for cost-benefit analysis of disposal options to help the electric utility industry and regulators reach cost-effective choices.

Under EPRI contract, Decision Focus, Inc., has developed a prototype framework for coal combustion by-product risk management and verified its major components on data for six utility disposal sites (RP2595). The next step in the project is to test the framework in actual utility applications. Potential applications range from determining the costs and benefits of an additional liner for a new disposal site to evaluating alternatives for remedial action at a site where a problem has occurred or may eventually occur.

Because only a few disposal sites and only some of the important aspects of groundwater chemistry have been studied in detail, the framework uses expert judgment where data are lacking or where uncertainties are significant. Although more site-specific and geochemical data are being analyzed, it may take years to complete the necessary research. In the solid waste environmental studies project, EPRI is conducting a major research effort to better understand the scientific issues in by-product disposal. Meanwhile, disposal decisions must be made on the basis of what is already known. The risk management framework developed in this project provides a means of reaching the best decision on the basis of the information available today. The framework relies on the techniques of decision analysis, a quantitative method for analyzing decisions that have complex and uncertain consequences.

Decision analysis is used to incorporate expert judgment into those parts of the analysis where data are lacking or where uncertainties are significant and to govern the level of detail in the analysis. Expert judgment is explicitly included in the analysis by means of probabilities that summarize judgment on the likelihood of the occurrence of an event or the accuracy of a scientific hypothesis.

These probabilities quantitatively describe uncertainties so that researchers can explicitly include them in the decision-making process and can examine the decision implications of differences in judgment.

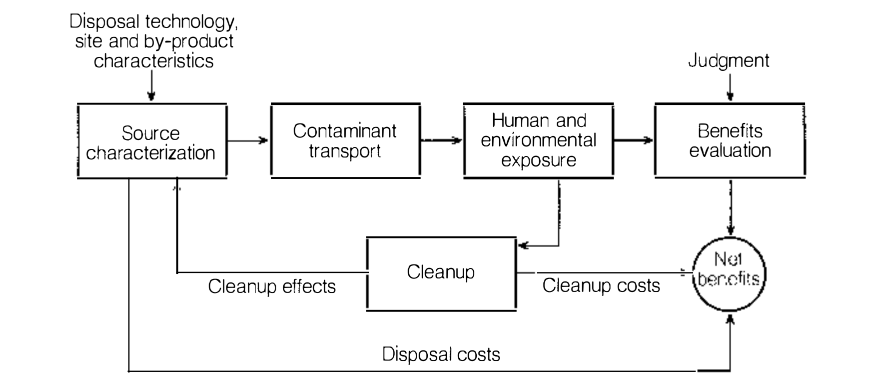
The level of detail of the analysis is determined by the need to discriminate among decision alternatives. For example, even though a variable (such as the rate of groundwater flow) may be uncertain, the appropriateness of a decision alternative (such as installation of a single or a double liner at a disposal site) may be the same for the plausible range of values of that uncertain variable. In that case, the uncertain variable will be downplayed in the analysis, and effort will be focused on the factors that determine the choice between a single and a double liner.

Decision framework for disposal alternatives

Estimating the costs and benefits of disposal technology alternatives is the primary goal of the decision framework. The costs include expenditures for the disposal technologies themselves as well as the potential costs of remedial action, if it is required. The benefits include reductions in the degree of groundwater contamination for specific substances of concern and, if relevant, reductions in the level of human exposure to those substances.

A scenario represents a set of assumptions about key variables that determine the costs and benefits of the decision alternatives. A decision tree is used to define the scenarios to be

Figure 3 Decision framework for estimating the net benefits of coal combustion by-product disposal options. Through its five modules, the framework enables the user to assess a technology's effectiveness in protecting groundwater and to balance the resulting benefits against the costs involved (disposal costs and the costs of possible remedial action).



evaluated by the deterministic framework and to incorporate the important uncertainties into the analysis.

Figure 3 shows the structure of the deterministic framework for analysis of disposal decisions. The first module of the framework characterizes the contaminant source. This module uses the site and by-product characteristics, disposal decision, and subsequent cleanup decisions to predict emissions, disposal costs, cleanup costs, and revenues from recycling of wastes. Emissions are characterized by the quantity of leachate and the concentrations of substances of concern in the leachate.

The contaminant transport module of the framework determines how contaminants move through the groundwater system. An important component of this module is the calculation of adsorption of contaminants onto soil particles in the aquifer. Adsorption attenuates the concentration of contaminants in groundwater and slows the migration of contaminants from the site. This module calculates the mass and concentration of contaminants in the groundwater over time and distance from the site and in surface waters fed by the groundwater.

The human and environmental exposure module of the framework is intended to assess all health and environmental impacts associated with the contaminant emissions. Such analysis can be very difficult to do. Therefore, for the present, the framework does not try to model such effects. It merely assumes that a decision (such as not exceeding existing exposure levels) will be made. If, for whatever reason, a cleanup of the site or some other action to prevent human exposure is required, the framework has to reflect the resulting reduced risk of exposure. To represent remedial action, the decision analysis framework includes a module for cleanup.

Representing uncertainty

Decision trees are used to specify the various scenarios of interest and to represent uncertainty about key elements of the deterministic framework. Figure 4 shows the basic structure of such a tree. First there is a choice of disposal technology. The choice of technology includes specification of whether wet or dry disposal is to be used, which disposal site is to be used, whether a liner is to be used (and if so, the type and thickness of the liner), and so on. These choices have different costs and imply different likelihoods of impact on the groundwater.

The second node of the tree is the uncertainty node representing the likelihood of contaminating the groundwater. The effect on groundwater is categorized according to whether or not it exceeds a threshold. The threshold is defined in terms of the levels of particular substances of concern, the depth at which measurements are taken, the distance (from the disposal site) at which measurements are taken, and the time (after waste disposal occurs) at which measurements are taken. The values of these parameters might typically be governed by the potential for human or agricultural use of the water. The operational definition of the threshold, however, is the level of contamination that would necessitate some form of cleanup or corrective action.

When significant contamination occurs, a decision must be made as to the type of corrective action to be taken. This decision is represented by the third node of the tree. Examples of corrective actions include capping the disposal site to reduce percolation through the waste material, installation of a slurry wall to prevent or divert the flow of leachate, and installation of extraction wells to extract leachate for treatment. Each of these corrective actions potentially affects the quantity and quality of the leachate leaving the site.

The final node of the tree is the node representing the uncertainty about the concentration and mass of the contaminant as it reaches receptors. Because receptors are typically sensitive to both the concentration and the to-

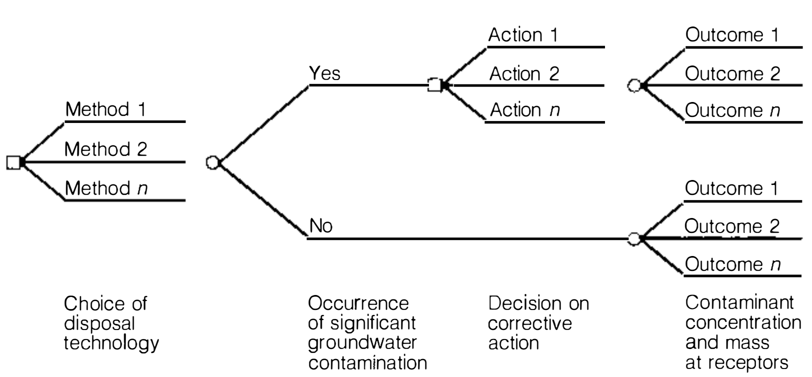


Figure 4 Basic decision tree for examining alternative coal combustion by-product disposal scenarios. Two decision points (squares) represent choices regarding disposal technology and corrective action, and two uncertainty resolution points (circles) address the occurrence and extent of contamination.

tal loading of a contaminant, both dimensions are addressed.

Figure 4 is a condensed representation of a full decision tree. In actuality, there is a node representing the occurrence of significant contamination for each end branch of the technology choice node; if there were significant contamination, there would be a decision node for corrective actions; and for each branch of the corrective action choice node, there would be a node representing the outcome—the ultimate cost and benefits. Similarly, each uncertainty node shown in the figure represents a more complex structure of underlying uncertainties. For example, the uncertainty about the occurrence of significant contamination is derived from uncertainties regarding more fundamental parameters, such as the rate of groundwater flow, the concentration of contaminant in the leachate, and the concentration of certain chemicals in the aquifer soils. A tree representing all important uncertain variables can be quite complex.

Example calculations

The features of the framework can be illustrated by several calculations. For that purpose a hypothetical site was examined where ash is disposed in a landfill and the contaminant of concern is arsenic.

In the source characterization module of the framework, the quantity of leachate produced at the site and the concentration of arsenic in the leachate were calculated. For dry ash disposal, for example, the quantity of leachate depends primarily on the amount of rainfall. The concentration of arsenic in the leachate depends on the quantity of the arsenic in the ash and its propensity to leach out of the ash particles.

In the contaminant transport module of the framework, for example, the migration of arsenic from the site is calculated. Migration depends on both groundwater flow and the chemical reactions between the leachate and soil. Groundwater flow depends on the gradient and on the permeability of the soil. The soil and leachate chemistry determine the propensity for arsenic to be adsorbed by soil particles and thus not migrate further from the disposal site. Because all these factors are typically uncertain to some degree and some are uncertain over a broad range, they strongly influence the uncertainty regarding the contaminant concentration over time at lower points along the down gradient.

For the hypothetical site examined here, a probability tree was set up to specify plausible distributions of values for the many uncertainties. Source characterization and contaminant transport calculations were then performed for each scenario specified by the tree. The concentration of arsenic at the disposal site boundary was calculated for each scenario. Then a cumulative probability distribution for all the scenarios was created. In the example, the probability of exceeding the primary drinking-water quality standard of 50 ppb arsenic is 4 in 100.

The cumulative probability distribution can be used to consider the decision on whether to add a liner to the site to decrease the migration of contaminant. For these illustrative calculations, lining the disposal site was assumed to reduce the emissions of leachate to a level that implied no violation of the drinking-water quality standard. The cost of the liner in this illustrative example is $10 million.

Not lining the site, however, results in a 0.04 probability of violating the standards. Remedial action in the contamination case was assumed to cost $30 million for capping the existing site, building a new site, and providing alternative sources of water for the parties affected.

Because contamination in this illustrative case has a small probability of occurrence, the expected cost of deciding not to line the site is small—$1.2 million (0.04 × $30 million)—compared with the cost of deciding to use a liner ($10 million).

The methodology developed in RP2595 provides an integrating framework for engineering, hydrologic, and geochemical information relevant to decisions on the choice of disposal technology for coal combustion by-products and similar solid wastes. Though better understanding of fundamental geochemical processes is highly desirable, the research needed to achieve such understanding may take years or even decades to accomplish. Meanwhile, decisions have to be made on the large volumes of solid waste that result from coal combustion. The risk management methods developed in this project provide a means of including the uncertainties that characterize the information available today. Given that today's decisions on waste disposal must be made in the face of large uncertainties, the methodology should prove useful to utilities, regulatory agencies, and other concerned parties in reaching agreement on the appropriate choice of waste disposal technology. *EPRI Project Manager: E. Victor Niemeyer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

ADVANCED FUEL CELL TECHNOLOGY

EPRI's advanced fuel cell technology subprogram has two basic objectives. The first is to increase the efficiency and reduce the cost of the near-term phosphoric acid fuel cell (PAFC) system by developing improved electrochemical components for the fuel cell stack. This includes advanced concepts that go beyond technology based on the use of phosphoric acid as electrolyte. The second is to develop high-temperature fuel cells whose efficiency with natural gas or clean light-hydrocarbon fuels is substantially higher than that of PAFCs. Present emphasis is on the development of fuel cells using molten carbonate electrolyte for longer-term use by electric utilities. The December 1984 status report discussed the recent development of the molten carbonate fuel cell. This report concerns the progress made in advanced PAFC and other acid technology since the last report on this subject in the September 1983 Journal.

The electric utility PAFC is now approaching the commercial stage. In January 1985, United Technologies Corp. and Toshiba Corp. began a joint venture in South Windsor, Connecticut (International Fuel Cells, Inc.), whose primary purpose is to make a commercial successor to the preliminary design known as the FCG-1 (fuel cell generator No. 1) described in EPRI EM-1566 and EM-3161. Although the power plant specifications are not yet final, this unit will be in the 11-MW (ac) class, will operate on natural gas or clean light-hydrocarbon fuel, and will have a fuel-ac higher-heating-value heat rate in the range of 8000 Btu/kWh (42.7% efficiency).

Like all currently envisaged fuel cells, FCG-1 will electrochemically oxidize hydrogen in the fuel cell stack by using atmospheric oxygen to produce dc power, which is then converted to utility-quality ac by a solid-state inverter. The hydrogen is produced by steam-reforming the desulfurized fuel in a state-of-the-art reformer. After a water-gas shift reaction to reduce carbon monoxide to low levels and to maximize hydrogen production, the resulting hydrogen–carbon dioxide mixture is consumed in the fuel cell's anode until its hydrogen content reaches low levels. Typically, hydrogen utilization in the cell is 85%. Going beyond this level is not practical as reaction efficiency begins to fall off rapidly. The anode tail gas is not wasted, however. The remaining hydrogen, along with excess carbon monoxide and methane (or other hydrocarbons), can be burned in the reformer to provide the heat of reaction.

Hydrogen is oxidized in the fuel cell at high thermodynamic efficiency, thus with little waste of energy. This is an improvement over past attempts to use hydrocarbons directly in the PAFC and justifies the use of the steam-reforming process. In contrast, the oxygen reduction process at the fuel cell's cathode (to complete the overall reaction, yielding water) is rather inefficient in the phosphoric acid electrolyte, even at the high cell operating temperature of about 200°C. To the consequent energy penalty must be added other small losses, particularly those due to internal resistance of cell components. The result of these losses is that when hydrogen is oxidized, the cell voltage developed is less than the theoretical value. Under theoretical room temperature conditions, the maximum free energy available in the process is about 1.23 V. This drops to about 1.15 V at a 200°C reaction temperature. The FCG-1 will be designed to operate at a cell voltage of about 0.73 V.

If 0.73 V is liberated in the form of electric energy, then 0.42 V is available as heat at the operating temperature of the cell. This waste heat, available from the cell stack, is more than enough to raise the high-pressure steam required for efficient reforming. The product steam formed by hydrogen oxidation can also be used. In the proposed FCG-1 flowsheet, the steam is condensed to provide hot water for cogeneration purposes, as in the United Technologies gas utility 40-kW on-site fuel cell. However, in the alternative Westinghouse Electric Corp. 7.5-MW electric utility PAFC design, which uses an air-cooled stack rather than a water-cooled system (used in the FCG-1), the steam is condensed to provide some of the compression work for the air turbocharger. The Westinghouse system is described in an early form in EM-1365 and more recently in DOE/NASA/0290-1 (NASA CR-174732). Turbochargers are common to all multimegawatt electric utility PAFCs because they improve air cathode performance, hence stack efficiency, and can be operated mainly on waste heat from the reformer gases with little or even no (in the case of the Westinghouse design) extra fuel penalty.

The proposed systems are carefully integrated to operate at overall efficiencies close to the calculated values. For example, the proposed FCG-1 operating at 0.73 V and 85% hydrogen utilization would have a theoretical dc lower-heating-value hydrogen utilization efficiency of $(0.73 \times 0.85)/1.28$, or 48.5%, which is equivalent to 42% on the basis of the higher heating value of the hydrogen produced. This corresponds very closely to the system higher heating value calculated on the basis of natural gas use and attests to the very high efficiency of the integrated reforming system. It is therefore almost impossible to raise efficiency by further modification of the chemical engineering part of the plant, which is already essentially 100% efficient. Any further gain in overall efficiency must be made in the fuel cell itself by increasing the voltage up to the limit dictated by the steam-raising requirements for reforming. A probable upper limit, based on this requirement, would be about 0.83 V with present PAFC system designs. If it could be attained, this cell voltage would allow a system heat rate close to 7100 Btu/kWh.

EM-3205 showed that a PAFC could be used in about 7% of the total added electric utility replacement capacity in the decade 1995–2005 (approximately), provided that the fuel cell has a mature capital cost on the order of $800/kW (1982 dollars) and a heat rate of about 8300 Btu/kWh. Reducing this heat rate (at the same capital cost) to 7500 Btu/kWh could triple the market, with very large fuel cost savings to the electric utilities. Hence market pressure will force the manufacturer to seek improvements in heat rate, particularly as fuel prices rise faster than inflation.

Cell voltage increases to improve the PAFC system's heat rate may be made in a number of different ways currently being addressed under the advanced fuel cell technology subprogram. One way, lowering internal resistance losses in the fuel cell stack, could result in a small gain (perhaps up to one incremental percentage point) by improving contact of conducting separator plate components between cells (perhaps by the use of a one-piece plate-electrode system). The use of a thinner electrolyte matrix would also be an improvement. This engineering approach to a marginally increased efficiency has one major advantage—it does not increase the absolute electrochemical potential of the cathode and therefore does not make the corrosion environment of cathode components more severe.

As indicated in the September 1983 status report, the rates of corrosion of the carbon or graphite components at the cathode increase rapidly with increasing absolute cathode voltage, typically doubling with each 30-mV increase in potential at constant temperature, corresponding to an increase in efficiency of ~1.7 incremental percentage points. Corrosion rate also increases with temperature and is proportional to water-vapor pressure.

Another method of improving system efficiency with existing catalyst technology is to increase cell operating temperature and system pressure, which are related through the ability to raise the temperature and high-pressure steam by using stack waste heat. As an example, an increase in cell temperature to 220°C with an accompanying increase in gas (including water-vapor) pressure would result in a cell potential of 0.78 V, for a system efficiency of 48%. At the same time, corrosion would rise more than 10-fold because of the combined effect of cathode voltage, temperature, and water-vapor pressure. This is beyond the capabilities of known cathode materials. As indicated in the September 1983 status report, electronically conducting carbides, such as those being developed by Giner, Inc., in RP1200-8, may eventually provide a solution to this problem. However, the corrosion rate of high-surface-area titanium carbide produced so far under this contract has had poor reproducibility. Attempts will be made to prepare other carbide materials, particularly doped silicon carbide.

Other methods aim at improving system efficiency at the cathode. More effective electrocatalysis of the oxygen reduction process would allow higher cell voltage without the use of higher temperatures and pressures and a greatly increased corrosion rate. In fact, it may be possible to reduce operating temperature and still increase cell voltage if a catalyst of higher activity than the current cathode material could be developed. Current catalysts are platinum alloys with refractory base metals, particularly chromium or vanadium, alone or in combination with other materials. Such catalysts were examined under RP1200-5, and this work is now being extended under RP1200-2 to develop more-stable alloys with a low rate of loss of activity as a function of time. Such alloys should be about 30 mV more active than pure platinum, and they should retain this activity without showing corrosion or recrystallization.

A more dramatic improvement in activity may come about with the use of stable sulfonic acid fluoropolymers in contact with the oxygen reduction catalyst. These polymers should allow a further improvement of about 50 mV compared with phosphoric acid because of their higher molecular oxygen solubility and its consequent effect on oxygen-electrode kinetics. These materials are being developed under RP1676-3, and kinetic studies on the polymers are being conducted under RP1676-2 and RP1200-7. As stated in the September 1983 status report, fluorinated sulfonic acids have very poor proton conductivity under expected utility operating conditions; thus the original hope that they might be used alone as electrolytes has had to be abandoned. However, their use as polymers in the electrode structure combined with, or as a substitute for, Teflon holds promise for a substantial improvement in cathode performance. In cells using this concept, the ionic conductor in the cell will still be phosphoric acid dispersed in the matrix material. The fluoropolymer acid (which may be based on phosphonic or phosphinic groups or other acid elements) will be present in thin (about 1–10 μm) layers in the electrode itself and would have negligible internal resistance losses. This development is being actively pursued under RP1200-7 and RP1676-2.

The effect of this innovation on state-of-the-art PAFC performance (system heat rate), or on capital cost of the stack at the original heat rate, is shown in Figure 1. It may result in better utilization of the electrocatalyst than is possible with electrodes made today; that, too, will further improve cell performance. In addition, the fluoropolymers may provide a more benign corrosion environment than phosphoric acid, giving the cathode component greater durability and a longer service life. *Project Manager: John Appleby*

COMMERCIAL-SECTOR DEMAND-SIDE MANAGEMENT ACTIVITIES

Since 1977 EPRI has conducted periodic surveys of utility demand-side management projects, focusing principally on the residential sector. The results of these surveys have been used to characterize trends in technology-re-

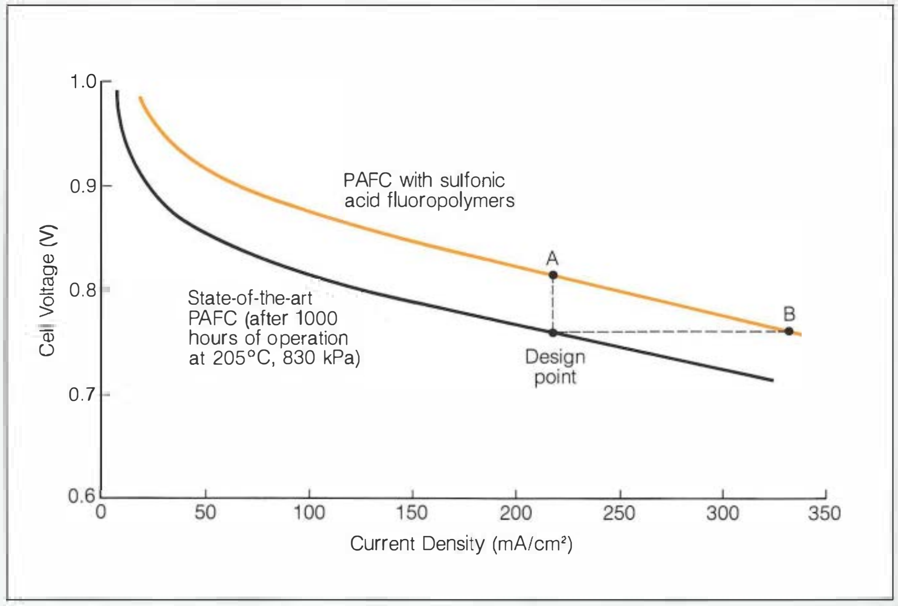


Figure 1 Projected effects of incorporating sulfonic acid fluoropolymers into the cathode of a state-of-the-art phosphoric acid fuel cell (PAFC). At point *A*, the higher voltage promised by the improved cell corresponds to a 500-Btu/kWh decrease in the present design point system heat rate. At point *B*, the improved technology achieves the present design point cell voltage (and system heat rate) at a higher current density; the result is a one-third reduction in stack capital cost.

lated activities, to facilitate exchange of information among electric utilities, and to identify areas that could benefit from R&D. A new survey conducted by Synergic Resources Corp. in 1984 represents a first-time examination of the commercial sector (RP1940-12). This area incorporates a larger variety of end-use equipment and exhibits less-predictable energy usage patterns than does the residential sector.

Survey scope and methodology

The survey gathered data on the following general categories of commercial demand-side management activities: efficient energy use, thermal energy storage and dual-fuel heating, load control, load development, special rates, load research, cogeneration, and solar technologies.

Efficient energy-use technologies are aimed at lowering end-use energy requirements by improving the building envelope or raising equipment efficiencies. The most popular of these include building insulation, heat pumps, high-efficiency air conditioning and water heating equipment, heat recovery devices, and high-efficiency lighting.

Thermal energy storage and dual-fuel heating systems can reduce or eliminate the peak period demand of customer loads without affecting customer comfort levels. Thermal energy storage systems store heating or cooling generated during utility off-peak periods for later use during peak periods. They fall into four categories: storage space heating, storage water heating, storage cooling, and storage for both heating and cooling.

Dual-fuel heating systems are switched by the utility from electric operation to backup fuel (usually oil or liquefied petroleum gas) operation during peak periods, thereby removing the entire load from the peak. A number of utilities have also observed that customers who use fossil fuel find it cost-effective to switch to electric heating by dual-fuel systems.

Load control is the modification of customer usage of end-use equipment to produce an overall change in the utility's load profile. Direct control is utility-initiated, real-time control over customer loads, implemented by a remote communication link between the utility and the controlled end use. Local control uses after-the-meter hardware that opens or closes circuits in response to data monitored at the end-use site. The hardware is generally purchased and installed by the customer to reduce electric bills. Distributed control is a hybrid of direct and local control in which after-the-meter control hardware is linked to the utility by remote communication, but end-use site data are monitored and used to determine the appropriate control actions.

Load development activities include various programs intended to encourage cost-effective and more-efficient uses of electricity. Special rates are also intended to modify load shape without focusing on any particular technology and include time-of-use, interruptible, off-peak, seasonal demand, and other rates structured to encourage electricity use during periods of greatest availability. Load research projects involve surveying commercial customers, collecting data on equipment saturation, developing reference load profiles for measuring the performance of demand-side management programs, and studying customer attitudes toward various demand-side management concepts.

The solar category covers active and passive solar heating and cooling, solar water heating, and biomass programs.

Cogeneration involves the generation of electricity and heat by customers for use onsite, typically with the possibility of selling excess energy to a utility.

Within each of the activity categories, utility projects were identified as to type of activity (e.g., equipment tests, promotion programs, customer support), types of participating commercial customers, types of end uses involved, and project objectives.

Survey findings

This survey identified 196 commercial-sector demand-side management projects reported by 113 investor-owned, public, and cooperative utilities (Table 1). The most frequently reported project category was efficient energy use (41%), followed by thermal storage and dual-fuel heating (26%), and load control (19%). The individual project activity types varied, with 32% of the projects involving incentives, 31% involving customer support/technical assistance, and 30% involving tests or demonstrations.

The majority of projects reported (63%) were aimed at all commercial customers; the most frequently specified customer type was office buildings (19%). Air conditioning, the most often reported end use, was the focus of 35% of the projects; space heating, water heating, and lighting end uses were also frequently reported.

A total of 81 efficient energy-use projects, reported by 58 of the utilities surveyed, involved about 90,000 commercial customers. Projects most often (48%) involved promotion of efficient energy use in general. The specific end uses most frequently identified were lighting, air conditioning, and space heating. Examples included providing water heater wraps, substituting energy-saving lamps for existing lighting, replacing street lamps, and converting to more-energy-efficient air conditioners.

Thirty-nine of the utilities surveyed reported 50 thermal storage and dual-fuel projects, which represent roughly 50,000 equipment installations. Twenty-nine of the projects involved tests and demonstrations or R&D activities; 20 involved promotional activities, such as incentives or advertising. Storage air conditioning programs accounted for 26 of all reported projects. Load shifting was cited as the load shape objective for 33 of the projects, and 22 listed peak load reduction as the objective. Increasing off-peak load and load growth in general were mentioned as secondary objectives in 6 of the projects.

Because such systems usually represent a

Table 1
COMMERCIAL–SECTOR DEMAND–SIDE MANAGEMENT PROJECTS BY TYPE AND REGION

Project Type*	North-east	East Central	South-east	South Central	West Central	North-west	West	Total
Efficient energy use	18	2	18	8	6	12	17	81
Efficient energy storage and dual-fuel heating systems	14	4	12	6	9	1	4	50
Load control	8	2	13	8	2	0	5	38
Load development, special rates, and load research	7	5	3	2	5	3	6	31
Cogeneration	—	0	3	1	2	0	1	7
Solar	1	0	4	1	0	0	1	7

*Several projects cover more than one technology category.

large investment for the commercial customer, utility implementation strategies often require a rate or incentive structure that will provide an attractive payback to the customer. The survey found that the typical incentive is a time-of-use rate that provides time-of-day differentials in both energy and demand charges. Several utilities offered additional incentives, often linked to the size of the installation. For example, Otter Tail Power Co. offered low-cost financing to cover installation expenses, and Dallas Power & Light Co. and Southern California Edison Co. provided rebates of $150–$200/kW shifted to off-peak periods.

A total of 38 load-control projects involving 27 electric utilities were reported, representing roughly 50,000 commercial load-control hardware installations. Direct-control technologies were used in more than half of the projects, local-control technologies were used in about one-quarter, and distributed-control or a combination of methods was used in the remainder. Controlled end uses included air conditioning, water heating, and space heating. Eleven projects involved control of all end uses at each installation site.

Seven utilities reported on load-development projects, three of which involved information dissemination. Three other projects included incentives to encourage customers to add loads, such as electric space heating and outdoor security lighting equipment.

Twenty-one special rate projects were reported, covering time-of-use rates, demand rates, interruptible rates, and other special rates aimed at changing the load shape.

Six load research projects were reported. Five aimed at developing various end-use demand profiles for use in evaluating future demand-side management programs; the sixth monitored a special rate program. Three of these projects used telephone or mail surveys to collect information, and the rest used on-site recording meters to collect consumption data for specific end uses or customers.

Cogeneration systems are most widely used in the industrial sector because larger customers can better justify the investment in generating equipment and often have thermal loads that can be served by waste heat from this equipment. Cogeneration is still limited in the commercial sector. Seven utilities reported seven projects, five of which involved the use of customer-owned standby generators to meet on-site electricity demands and to provide load reduction during peak periods. These utilities typically notify their customers (by telephone or remote communications link) of an impending peak period and the need for customer generation, but direct control of the generating equipment is also possible.

Demand-side management involving solar technologies is limited; five utilities reported a total of seven solar projects in the commercial sector. Two involved equipment testing or demonstration activities, three involved promotion, and two combined testing and promotion. In three of these projects, solar equipment was included as one of numerous technologies aimed at improving overall building energy efficiency.

Many of the surveyed utilities provided information on load impacts in terms of peak kW or average annual kWh consumption. A sampling of these results follows.

- One of the direct-load-control projects achieved a peak reduction of 1 kW per customer from water heater control. Another achieved a 2.9 kW per customer average peak reduction from air conditioner control. Demand reductions as large as 350–380 kW per site were also reported, but these involved shedding entire customer loads (e.g., a water treatment plant) by utility signaling.

- Peak demand reductions brought about by thermal storage air conditioning projects, mostly in office buildings, ranged from 15 to 1690 kW per customer.

- Efficient lighting programs reported per customer demand reductions ranging from 0.8 to 6.8 kW, and annual energy savings between 627 and 2100 kWh over a wide range of commercial customer categories.

- Heat pump water heaters appear to perform well in restaurants. One utility reported average annual savings of 7020 kWh, a reduction of 43% compared with conventional water heater usage.

- A single customer cogeneration plant represented a 380-kW demand reduction for one reporting utility. Another utility reported a 3600-kW reduction from two cogeneration plants in office buildings in its service area.

All pertinent information collected on the 196 projects reported in this survey and the 953 projects listed in the *1983 Survey of Utility End-Use Projects* (EM-3529) have been entered in the computerized EPRI Utility End-Use Projects Data Base. The menu-driven software allows viewing of data for each project and sorting of projects by utility and state, or by combinations of region, utility type, customer class, project objective, end use, and technology category.

The data base is easily accessible by telephone; it requires only a microcomputer or remote terminal with communications modem and software. Having a printer or disk storage at the user's station is recommended because some output options may generate a substantial amount of information. For more information and instructions regarding the use of this service, contact the EPRI Technical Information Center at (415) 855-2411 and refer to the Utility End-Use Projects Data Base. *Project Manager: Veronika A. Rabl*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

DECONTAMINATION TECHNOLOGY FOR TMI-2 CLEANUP

Because the TMI-2 accident deposited fuel debris on the surfaces of many reactor components in the primary system, the recovery effort requires new cleaning (decontamination) techniques. TMI provides EPRI and the nuclear industry with an opportunity for R&D to identify mechanical and chemical decontamination methods that could be used not only at TMI-2 but in other utility applications as well. Initial laboratory studies followed by tests on TMI artifacts resulted in the design and development of new equipment with unique capabilities.

The accident at TMI-2 resulted in radiation and decontamination problems unprecedented in the nuclear industry. The dispersion of UO_2 fuel throughout the reactor coolant system and the deposition of loose debris on the surfaces of the system's piping, pumps, and tanks require the reevaluation of traditional mechanical and chemical decontamination methods to establish their effectiveness in removing fuel debris. Debris removal is especially important because it can be a potential radiation hazard to maintenance personnel working on recovery operations. TMI has made clear the necessity of developing delivery systems that can be remotely positioned and maneuvered in inaccessible areas. Accordingly, EPRI initiated work with Quadrex Corp. to evaluate mechanical decontamination methods (RP2012-6) and with Pacific Nuclear Systems and Services to evaluate chemical decontamination methods (RP2012-8).

The approaches used in the projects were similar. Researchers initially evaluated methods in the laboratory under closely and easily controlled conditions. They then used the best method(s) on artifacts removed from the TMI-2 site. If successful, a particular method was incorporated into equipment developed for use on a specific system at TMI-2. This approach was successfully implemented for mechanical decontamination methods, but only the laboratory studies have been completed for chemical decontamination.

Mechanical decontamination

The mechanical decontamination methods selected for the laboratory evaluations were propelled devices; pigs; rotating scrapers, cutters, brushes, and hones; and high/ultrahigh-pressure water. Researchers evaluated each technique for its ability to remove simulated loose fuel debris and an adherent corrosion layer, its ability to go through and clean 90° bends, and the condition of the cleaned surface. These tests were performed on type-304 stainless steel tubing specimens. They showed the most effective techniques to be high-pressure water (5–35 ksi, 34–241 MPa) and rotating hones, which are brushes with nylon bristles tipped with abrasive silicon-carbide particles.

Pressurized water was selected as the means of removing loose fuel debris and adherent ^{137}Cs from a section of the H-8 leadscrew taken from the TMI-2 site. The leadscrew has a smooth section of type-304 stainless steel and a threaded section of type-17-4 pH steel, both of which are typical materials found in the pressure vessel. Investigators tested the high-pressure-water method in a shielded facility equipped with a manipulator at Battelle, Pacific Northwest Laboratories; DOE provided partial support.

The research produced equipment with manipulators that accurately aligned the water jets with the section of the surface being decontaminated and allowed remote interchange of nozzle hardware. Radiologic evaluations showed decontamination to be a success. Although much of the loose fuel debris was lost (presumably in shipping and handling) before testing, the data suggest that flushing at ~5 ksi (~34 MPa) would effectively remove such material. Water at 35 ksi (240 MPa) pressure, 6 in (15 cm) from the target, and at a traverse rate of 37 in/min (94 cm/min) removed about 98% of the adherent ^{137}Cs. Decontamination factors (the initial radiation level divided by the postdecontamination level) were highest at the 6-in standoff distance. Researchers attributed this achievement to the effectiveness of erosion in removing adherent debris.

Because of the success of high-pressure water in cleaning the leadscrew, this technique was selected for incorporation into the equipment that would be used to decontaminate the TMI-2 reactor underhead and plenum areas. Although the equipment was never used for this purpose, it is worthwhile to describe it because it might have future applications at TMI-2 or in other nuclear plants.

The equipment had to meet stringent requirements because of its proposed use, the TMI-2 reactor design, and the availability of support equipment at the site. The flushing system had to (1) clean the entire surface of both the vessel underhead and the plenum, (2) be installed with the missile shields in place, (3) operate remotely from the service structure through a long (~17-ft, 5-m) manipulator support tube, and (4) recognize that access to the interior of the vessel was limited to openings through only five control rod drive mechanisms (at most).

Conceptual design, proof-of-principle testing, hardware fabrication, and performance testing (often on full-scale mockups of the TMI-2 structure) yielded two effective flushing systems. The first consists of a length of straight tubing and an assembly of three short tubular segments at the end. The upper section allows the segments to clean the control rod guide tube; the middle section provides coverage of the plenum floor; and the reversible 90° bottom section orients the nozzle for flushing the underhead and/or feeding onto the plenum floor.

The second system has a long tube that passes through the manipulator support tube and transmits water under pressure through a joint that can rotate or swivel through 90°. The end of this device contains the nozzle that delivers the high-pressure water. A 16-jet nozzle assembly body was selected to spray the water in a uniform radial pattern. Testing showed that a nozzle made from a sapphire insert bonded in a stainless steel plug produced the best results.

Other systems were designed and fabricated to assist in decontaminating drain lines and piping. These systems relied on rotating hones or pressurized water to remove debris. One such system, which enters the contaminated site through drain openings, uses a rotating hone fed by a plumber's cable. It can clean 4- and 6-in (10- and 15-cm) piping in lengths up to 45 ft (14 m). The engineering development focused on ways of attaching the hone to the cable and preventing the cable from jamming.

Chemical decontamination

Researchers tested seven chemical solvents on type-304 stainless steel and Inconel-600 steam generator tubing in the laboratory. In some cases, these solvents were combined and tested. The specimens were treated in water containing fission products (^{137}Cs and ^{90}Sr), and fuel debris was simulated by using depleted UO_2 in the form of pellets and fines (powder). Investigators used coupons of 10 different materials (both metals and nonmetals) to measure corrosion effects.

Measurement of decontamination factors on the tubing specimens and weight changes of the UO_2 pellets and fines showed the effects of each of the solvents. Researchers determined weight changes of the corrosion coupons and monitored these coupons for beta and gamma activity to estimate the potential for redeposition.

One process, OPG–AP–Citrox, was selected for additional testing. Two others, Can-Decon and LOMI, also yielded favorable results but were dropped from the program because their possible use required further development for this particular application, which involves dissolution of nuclear fuel. OPG is a concentrated solvent containing oxalic acid, hydrogen peroxide, and gluconic acid for dissolving fuel debris. AP-Citrox is a two-step process that uses an alkaline permanganate-oxidizing solvent followed by a reducing solvent (citric acid–oxalic acid) to remove corrosion deposits.

OPG–AP–Citrox was very effective in decontaminating the stainless steel specimens; the process achieved decontamination factors $\geqslant 100$. In addition, it was more effective in the presence of boric acid, which exists in the TMI-2 primary coolant. The process was most effective in dissolving UO_2 fuel fines but, like all the other solvents, did not dissolve intact fuel pellets. All the solvents studied induced little corrosion in the test materials, except carbon steel. (TMI has little carbon steel; the metal was included in the tests primarily because of its potential use in components making up field decontamination systems.)

The next phase of the research will include tests of the OPG–AP–Citrox process on artifacts from TMI-2: a coolant system tank cover and a section of the H-8 control rod leadscrew. Researchers will also work to improve the process's ability to dissolve fuel. Then they will test the chemical on actual TMI-2 fuel debris.

This work shows that a range of chemical and mechanical decontamination methods will aid the recovery efforts at TMI-2 by reducing radiation fields in systems that require further inspection and repair or that may have to be removed. Some of the mechanical methods may serve in nonnuclear applications. High-pressure water shows some promise as a concrete cutter (EL-3601, Vol. 1), and researchers will evaluate it (possibly with added surfactants) as a means of removing PCB contamination from porous surfaces. The brush hone has potential as a device for smoothing large surfaces of reactor piping; smooth surfaces are an important factor in minimizing recontamination. In addition, the unique delivery systems designed to introduce decontamination nozzles to inaccessible or inhospitable environments can readily be adapted to a variety of probes. Therefore, they may be useful in nondestructive evaluation. *Project Manager: Howard Ocken*

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ADVANCED POWER SYSTEMS

Guidebook for the Use of Synfuels in Electric Utility Combustion Systems: Liquid Fuels Derived From Shale and Tar Sands

AP-3348 Final Report (RP2106-1), Vol. 3; $25
Contractor: KVB, Inc.
EPRI Project Manager: W. Rovesti

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