On-Line Plant Monitoring

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Cover: Power plants are being wired with sophisticated sensors and computer monitoring systems to diagnose equipment problems and optimize operations.

On-Line Diagnostic Monitoring: Harbinger of a New Era

The microcomputer revolution has opened up new opportunities for power plant improvement. A notable example is the use of unique sensors to detect and interpret the minute perturbations in equipment behavior that signal the onset of a failure. This rapidly growing field is usually termed on-line diagnostic monitoring, since the sensing and diagnosis is done while the unit is still operating and producing power.

Today's utility engineer has an impressive array of sensitive devices available to him to detect early failure symptoms. These include low-power lasers, sensors that use magnetic fields to measure vibration or to detect cracks, piezoelectric transducers that listen for material fracture, infrared and ultraviolet detectors for boiler flame investigations, and X-ray and gamma-ray sensors. A review of commonly used techniques reveals that the entire electromagnetic spectrum is employed in diagnostic monitoring—a tribute to the ingenuity of the growing cadre of experts in this technology.

Many of these diagnostic techniques will be part of the plantwide predictive maintenance system now being installed at the Eddystone plant of Philadelphia Electric. This EPRI center for on-line diagnostics will be an important industry resource, both for validating the new technologies and for training utility engineers and technicians.

This is an exciting time for utilities, as the computing power in the silicon chip is directed toward the perennial issues of fossil plant efficiency and availability improvement. Diagnostic monitoring is the first of a number of computer-based technologies that promise to revitalize our installed generation. The industry is already moving toward expert systems and artificial intelligence techniques, to new opportunities in plant controls, and to an array of computer simulation packages.

With its long background of evolutionary advances, the electric power industry has experienced few dramatic changes. But in looking back from the year 2000, it is likely that the 1980s will be viewed as the time when the microprocessor began to significantly impact utility operations. Diagnostic monitoring thus portends things to come and, for the utility industry, a step forward in the constant search for increased power plant productivity.

Anthony F. Armor
Senior Program Manager
Fossil Plant Performance

DEPARTMENTS

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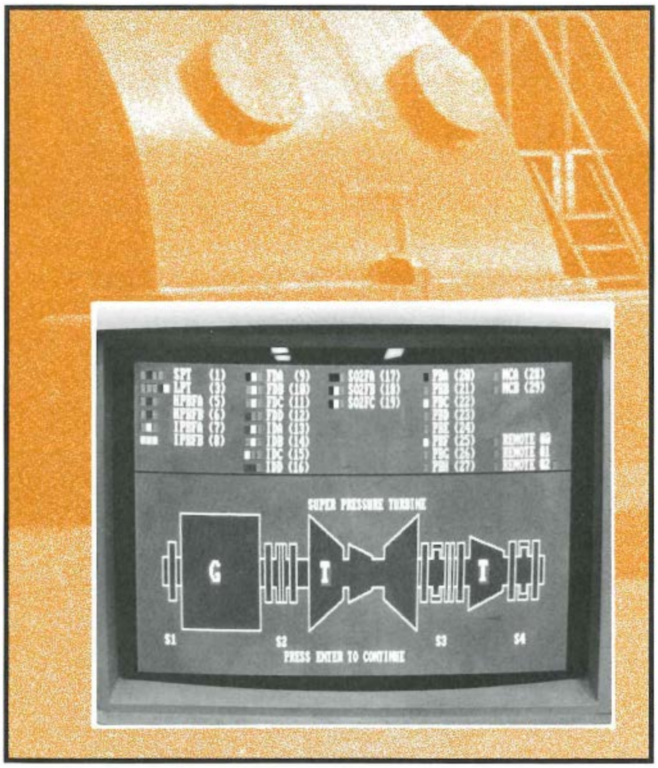

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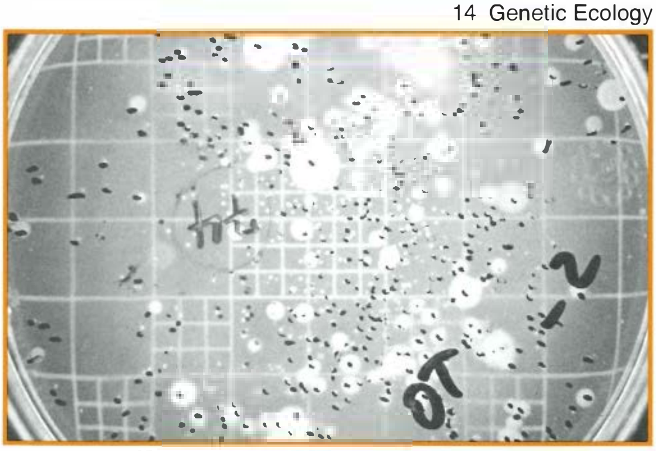
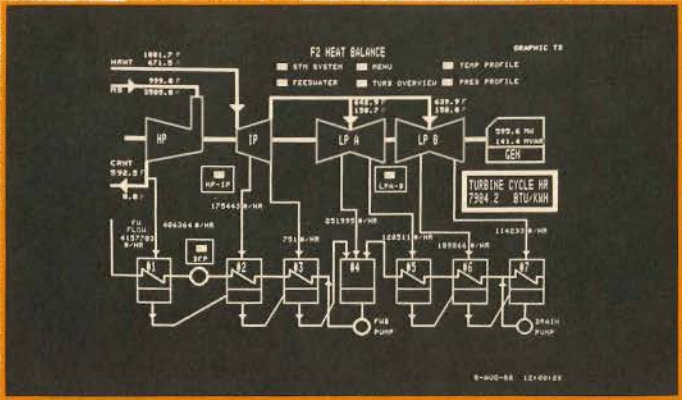
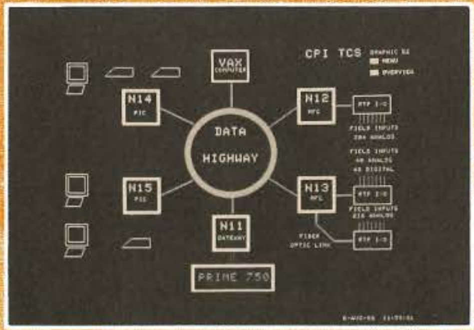
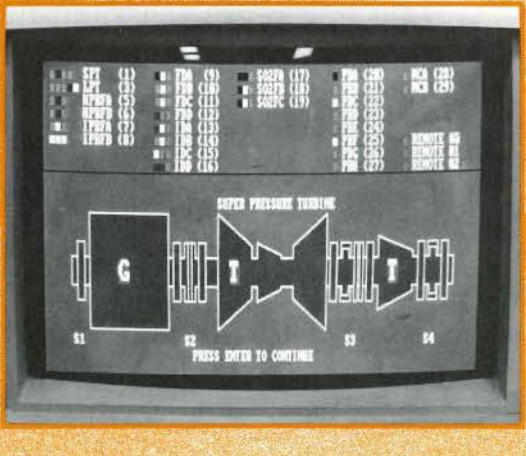
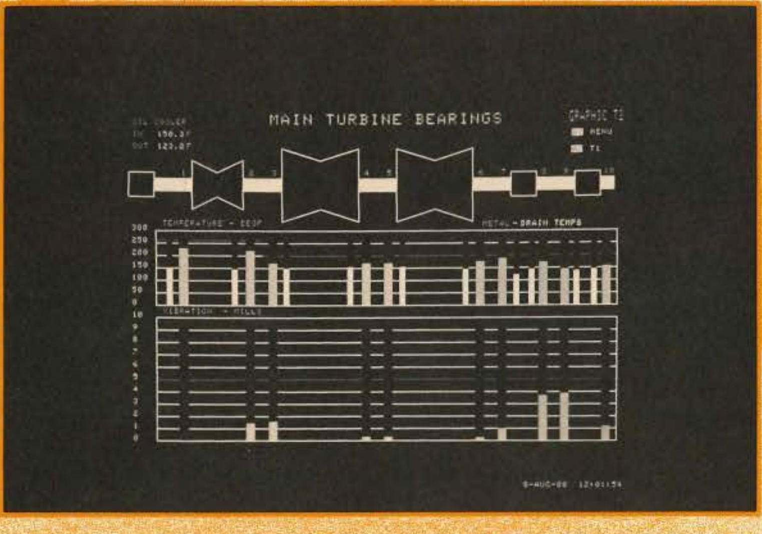




Pushing Performance With On-Line Monitoring







Facing new competitive pressures with a fleet of middle-aged plants, coal-burning utilities are turning to electronic sensors, microprocessors, and computers to improve performance and reduce maintenance costs. Two plants are becoming industry showcases in demonstrating the state of the art in performance and diagnostic monitoring.

New competitive realities and economic pressures are changing the role of some of the utility industry's mainstay generating plants. Long the backbone of baseload capacity, the coal-fired plants whose predecessors made possible the large-scale generation of electricity at the turn of this century are now expected to perform under new demands, constraints, and expectations.

Today, and increasingly in the future, coal-fired power plants must maintain a higher degree of readiness, operate longer under a wider range of dynamic loads, generate the maximum practical electricity from the fuel, control pollution emissions to a growing extent, and avoid costly equipment breakdowns, all the while as the effects of aging exact a certain toll on performance and economics.

"Sustaining low-cost production with an aging fleet of coal plants operated as cycling units will very likely require continuous equipment monitoring and advanced controls," says Anthony Armor, a senior program manager in EPRI's Coal Combustion Systems Division. As a result of both the new demands and the opportunities for electronic automation, "coal-fired power plants are adapting high technology into operations," Armor notes. "Sophisticated sensors and computer monitoring systems are finding their way into all areas of the plants, from the coal preparation end through the boiler and steam turbines to the environmental control and auxiliary systems," he adds.

"Over the near term, this trend will permit the fine-tuning and control necessary for better performance, availability, and reduced emissions. But it also presages broader, more fundamental change as coal plants evolve toward resource refineries generating a mix of products and using a variety of advanced and new technologies under an integrated process control system," predicts Armor.

For over a decade, EPRI has played a significant role in shaping that evolution, sponsoring the development or application of over two dozen new techniques for monitoring and analyzing a wide spectrum of power plant operational parameters. Computer algorithms and technologies to integrate, display, and act on the new data streams have also been a focus of R&D. Two major efforts are under way at Potomac Electric Power's Morgantown station and Philadelphia Electric's Eddystone plant to demonstrate and transfer into operating utility environments the state of the art in performance and equipment diagnostic monitoring and related controls. The projects are serving as industry test-beds while also generating documented economic benefits. And, looking to the early 1990s, EPRI research managers envision advanced plant simulators and artificial intelligence–based expert systems to train and assist the operators.

Beyond digital

The change from analog electromechanical controls to digital electronic controls across the entire range of technology used by modern society has become a hallmark of the last quarter century. From consumer products to automobiles, from steelmaking to petroleum refineries, microprocessors driven by digital data are the new engines of industry and information.

Utility power plants have been no exception to the trend in computerization. Some of the control systems and concepts that are common today were pioneered for nuclear plants, where safety standards and regulation drive a continuing quest for accurate, detailed, and real-time data on plant conditions.

Direct, digital controls first began to appear in fossil-fuel-fired power plants in the 1960s, although many of the quantities (temperature, pressure, flows) displayed to operators were still conversions of analog, often imprecise, measurements. Despite the advent of digital control room displays, actual plant operations have often remained a matter of hands-on, seat-of-the-pants decision making.

Although operators still run the plants, several trends have brought a growing degree of computerized control and periodic or continuous monitoring of major components and subsystems. For starters, utilities in nearly a third of the states are under explicit regulatory standards for improving the performance (heat rate and availability) of fossil fuel generating units.

Competitive pressures and reduced environmental control costs are among other incentives to generate electricity with the least possible fuel input. Extensive instrumentation for measuring heat flows and pressure drops all along the steam paths—as well as microprocessors programmed with algorithms to continuously integrate the diverse data—is essential for accurate heat rate measurement.

On the other hand, few new coal-fired plants are being built, and by the year 2000 over three-quarters of the plants in service today will be over 20 years old—half of them over 30 years old, notes Armor. As the plants age, efficiency gains become harder to achieve and maintenance costs go up. Many utilities are analyzing the economic trade-offs of extending the operating lives of existing plants, with extensive equipment monitoring systems and improved controls chief among the candidate areas for upgrade.

Meanwhile, modern electronics are transforming plant maintenance activities. Myriad sensors and probes linked to microprocessors for data collection, reduction, and analysis can discern the inaudible hiss of a pinhole boiler tube leak, ferret out the unique vibration signature of a misaligned turbine rotor, or detect incipient microscopic cracking or wear in turbine blades, among many other vital signs crucial to plant availability. The technologies range from sensitive microphones behind boiler tube walls to magnetic flux detectors passed along pipe surfaces to laser beams trained on rotating parts.

"Diagnostic monitoring and inspection equipment has grown so diverse that it spans the entire electromagnetic spectrum in terms of the types of signals that can warn of component degradation or approaching failure," notes Armor.

For example, at the low end of the spectrum, frequencies of up to about 1000 hertz contain the clues to turbine generator vibration problems. Ultrasonic frequencies can be used to reveal cracks and other developing problems in boilers and heavy-section turbine parts. Radio waves can detect generator arcing. Microwaves can be used to measure the moisture content of feed coal. Devices for detecting infrared energy can be employed for measuring the degree of thinning in boiler waterwall tubes or heat losses from boiler casings.

Ultraviolet frequencies present in combustion flames provide a means of monitoring the characteristics of burners in fossil fuel boilers. X-ray systems are used for inspecting boiler and steam headers. Even at the far end of the electromagnetic spectrum, researchers are using gamma rays emitted from the activated surfaces of turbine blades to track the rate of solid-particle erosion and wear.

In recent years, many equipment monitoring systems have become sufficiently rugged and have been accepted by plant maintenance crews to such an extent that they are now permanent fixtures at critical locations. Increasingly, sensor readings are routinely recorded and relayed to the control room or elsewhere, where engineers can look for trends in component degradation for warnings of approaching failure.

According to John Scheibel, an EPRI project manager in fossil plant diagnostics and nondestructive evaluation, plant maintenance philosophies are evolving toward an on-line, predictive capability, offering a 10–30% reduction in the typical multimillion-dollar annual plant maintenance budget. Today's conventional approach often involves some combination of reactive or run-to-failure maintenance and preventive maintenance, in which components are periodically replaced without specific evidence of degradation.

Both methods, however, can be quite expensive, either in plant downtime and replacement power costs when a

Showcase Demonstrations

In conjunction with EPRI, Potomac Electric Power and Philadelphia Electric are demonstrating and bringing together the latest technology for plant performance and equipment diagnostic monitoring. Each utility has outfitted one of its coal-fired generating units with a panoply of sensors, microprocessors, and on-line analytic systems for either improving plant performance or reducing outages and maintenance costs.

Flue-gas sampling and analysis system

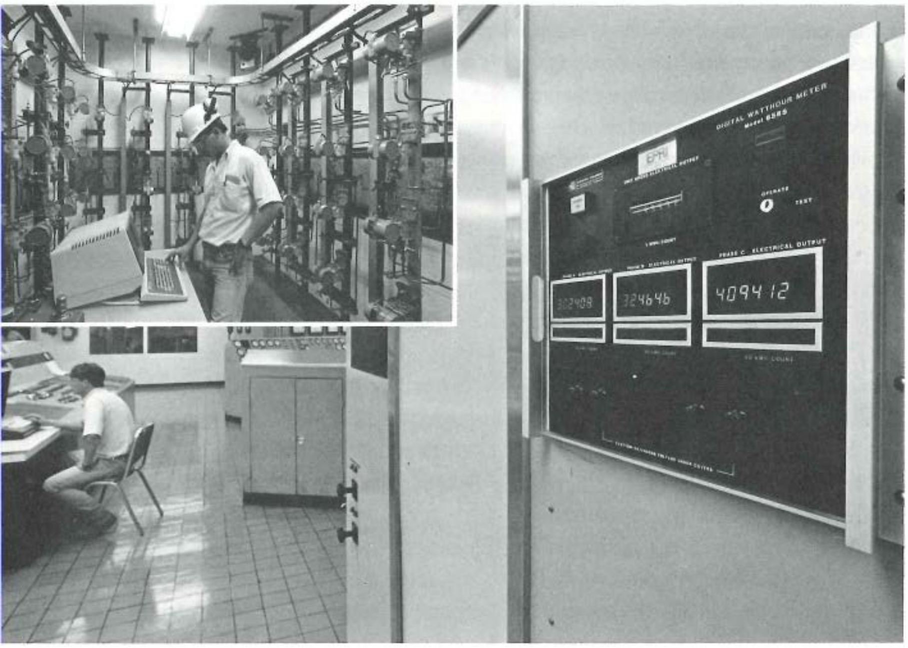
Predictive maintenance training

tegrating the State of the Art . . .

. . . In Plant Performance at Morgantown

Monitoring systems relay room

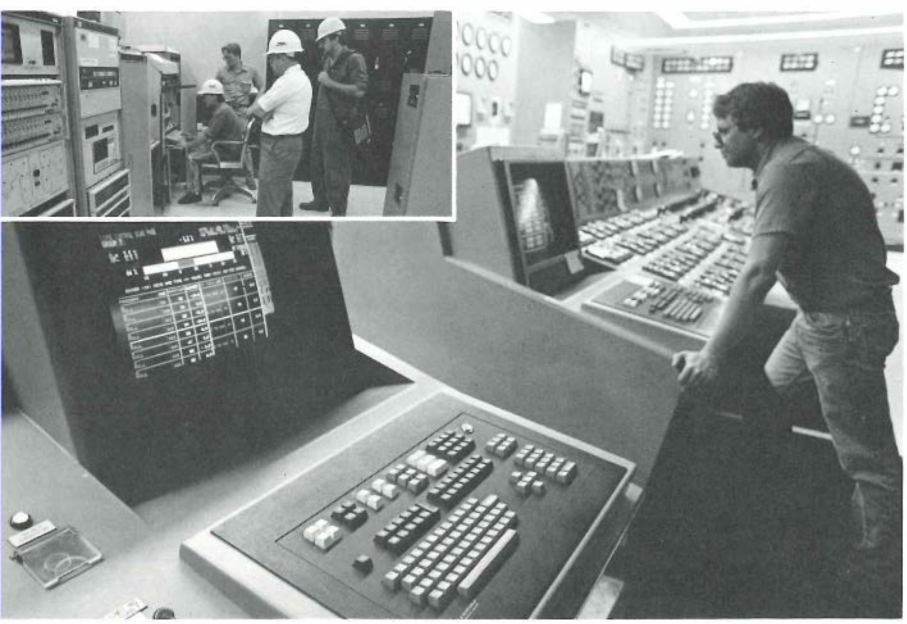
Digital watthour meter in plant control room



. . . In Equipment Diagnostics at Eddystone

Acoustic leak monitor and vibration analyzer

Diagnostic display console in control room



major component does fail (and perhaps damages other equipment along with it), or in too-frequent equipment changeouts. *Forbes* recently estimated that $1 out of every $3 spent by utilities on maintenance—or some $60 billion annually—may be unnecessary.

"A systematic program of regular machine monitoring to determine actual mechanical condition in operation has the potential for major cost savings with only modest investments in monitoring systems," says Scheibel. "By monitoring such machine parameters as vibration, electrical current, temperature, pressure, and other process variables and comparing these measurements with normal operation baseline readings, developing problems can be detected early on and followed. Repairs or shutdowns for replacement can then be scheduled more strategically," Scheibel explains.

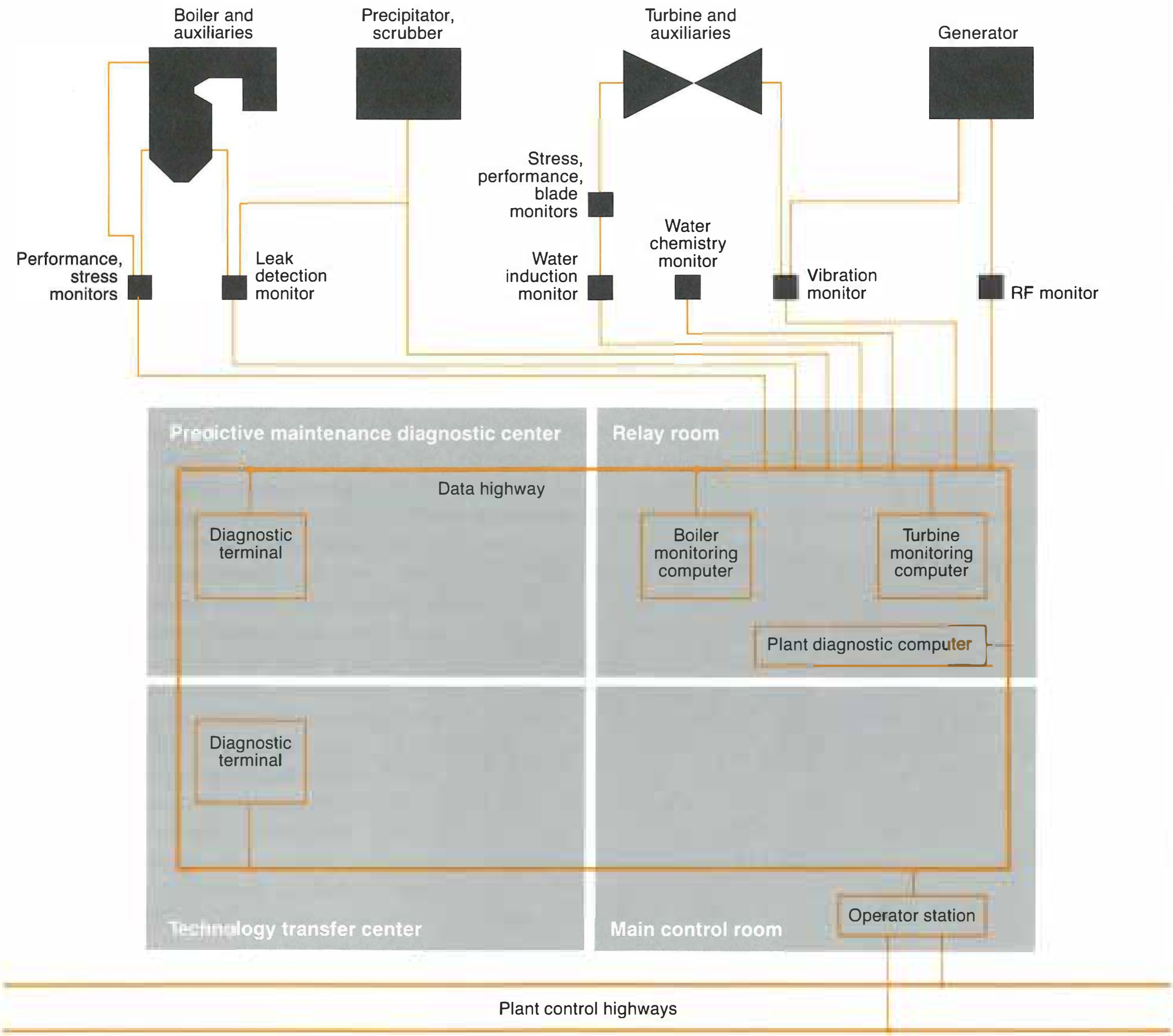
Whittling away at heat rates

Plant monitoring systems can be grouped into two broad categories: those related to improving the accuracy and control of heat rate (thermal efficiency) and those whose prime purpose is to diagnose component wear and impending failure. After several years of R&D on a broad front, on the part of EPRI, the generating equipment manufacturers, specialty engineering firms, and many utilities, there are now extensive arsenals of solutions in both classes for utilities to deploy in campaigns against degradation of performance and equipment. And still more reinforcements are on the way.

Optimizing a plant's heat rate is an area where improvements translate directly to a utility's bottom line. The more efficient the thermal performance, the more revenue-producing kilowatthours are generated from a given amount of fuel, which accounts for 75–80% of a coal-fired plant's operating expense. A plant with poor heat rate may, in effect, have hidden, unused

On-Line Predictive Maintenance Emerging at Eddystone

For the first time, a coal-fired utility generating plant is demonstrating the full potential of diagnostic monitoring in a predictive maintenance program for boilers, turbine generators, environmental controls, and balance-of-plant equipment. EPRI and Philadelphia Electric have equipped Eddystone Unit 2 with sensors and monitoring systems on every major plant component. The sensors are integrated with various computers and diagnostic display terminals via a fiber-optic data highway that links all areas of the plant. New monitoring systems and diagnostic techniques can be evaluated with the plant's extensive instrumentation and data analysis capability. A technology transfer program already under way is training utility engineers from around the country in diagnostic monitoring.



generating capacity. Hammering down the heat rate can also reduce the cost of chemical reagents, the need for auxiliary power, and the cost of solid-waste disposal for flue gas desulfurization systems.

A typical large coal-fired plant that is 34% efficient requires about 10,000 Btu of heat in the boiler for every kilowatt-hour leaving the generator at the busbar. EPRI studies suggest that an attainable 4% improvement in heat rate, or only 400 Btu/kWh, can reduce a plant's generating cost by $4 million a year.

Traditionally, plant heat rates were optimized for steady-state conditions under baseload operation. Clearly, it is easier to get the highest efficiency when a plant is operated at high capacity continuously (much as greater automobile fuel efficiency is obtained during long highway trips).

But coal-fired plants today are seeing a lot more city driving—that is, they're being used increasingly as intermediate or cycling capacity, increasing output as load climbs and throttling back at times of reduced demand. Not only does this kind of operation add significantly to the stress and strain that accumulates in key components, but it greatly complicates attempts to use the fewest Btus to satisfy the demand for power.

EPRI's programs in plant performance and cycling operation have included several major industry conferences in the last two years, technical guidelines, and continuing case studies at individual utility plants. Nine ongoing demonstrations at operating units will verify and disseminate the best approaches for cycling conversion and heat rate optimization. Special hardware and related software, some developed with EPRI support and some offered commercially by vendors, are being tested and evaluated for their potential economic benefits.

But it is at one plant in particular—Unit 2 of Potomac Electric Power's (PEPCO's) Morgantown station in Charles County, Maryland—where all elements of the state of the art in performance monitoring are being integrated as an industry showcase. The 575-MW supercritical unit, in Armor's description, "is a full-scale boiler and turbine cycle test bed for validating and commercializing new sensors and monitoring instruments."

Adds Robert Leyse, the project manager, "It's all coming together. Key boiler and turbine parameters are being measured on a continuous basis. Many of the systems installed and proved at Morgantown are beginning to be used by the industry at large."

For the boiler, innovations applied at Morgantown include an improved system for monitoring wear in waterwall tubes. A combustion optimization simulation code is used for establishing boiler settings. And an on-line output/loss measurement technique integrates data from throughout the plant to provide a continuous readout of heat rate accurate to about 50 Btu/kWh, compared with an accuracy of, at best, 200 Btu/kWh for fuel-based, noninstantaneous calculations.

Other parts of the Morgantown demonstration are focused on the turbine, where even minor steam leaks or inaccurate measurements can mean the loss of generated power—10 MW in one documented case. Products include a method for directly measuring the steam that leaks through internal packings between the opposed sections of a high-pressure/intermediate-pressure turbine. Another monitor translates measurements of temperature and pressure in the turbine throttle and first stage to calculate the control-valve position to within 2%. Knowledge of when a control valve is just about to open can be used to dispatch the unit more economically.

A related control-valve alignment system allows engineers to identify and adjust misaligned control valves, which can cause a turbine to respond inconsistently, and therefore inefficiently, to load changes. Also, a refined diagnostic procedure for accurately determining key conditions inside an operating turbine is helping PEPCO to plan maintenance better. The utility estimates savings of $200,000 a year from optimizing its turbine overhaul schedules.

As only one example of an innovation at Morgantown that has already been applied at another utility plant, a monitor for accurately measuring condenser pressure is now also in use at Minnesota Power's Clay Boswell station. Condenser pressure, synonymous with the pressure at the back end of the turbine, has heretofore been difficult to measure because of unreliable sensors and moisture collection in the sensing line. The new system samples 16 pressure taps at the low-pressure turbine exhaust linked to pressure transmitters, a central computer, and a small programmable controller. Continuous readouts of condenser pressure contribute to more-accurate calculation of plant heat rate.

Accurate heat rate calculation is also dependent on precise measurement of generator electrical output. Standard polyphase meters are insufficiently precise for three-phase circuits to avoid errors from unbalanced phases. A new solid-state watthour meter developed to PEPCO specifications and now used by many utilities continuously records three-phase output within ±0.05%—a factor-of-5 improvement over conventional meters. The data are automatically integrated with the plant process computer for heat rate calculation.

"All told, the innovations applied at Morgantown have given PEPCO the capability for improving heat rate by 3%, or as much as 300 Btu/kWh," says Leyse. The project will continue through the early 1990s, culminating in a series of technology transfer efforts. Utilities themselves have estimated that heat rate gains achievable at other fossil fuel plants could range up to 15%, with an average of 4% improvement.

Reducing maintenance costs

Besides fuel, the other major component of plant production costs is maintenance; maintenance costs can range from 20% to 25% of the total. In addition to direct savings, a more anticipatory maintenance strategy also promises broader benefits from improved plant availability and reduced forced outages and replacement power costs.

Such a strategy, according to Scheibel, should be centered around a trio of diagnostic monitoring technologies: stress analyzers for monitoring temperatures and assessing damage to boiler headers and turbine rotors; acoustic leak detectors for advance warning of boiler tube, header, and steam line leaks; and vibration monitors for critical rotating machinery, including turbine generators and major fans and pumps.

Many utilities have already installed acoustic leak detection systems in boiler furnaces, convection passes, and penthouse areas. Off-line, nondestructive materials testing is also used for assessing the extent of creep and fatigue damage to thick-walled components. And even periodic vibration tests are performed on such items as turbine rotors to spot the onset of dynamic instabilities, misalignment, transverse cracks, and other damage.

But the goal is to refine the technology for turning more of these diagnostic efforts into continuous, on-line systems capable of sustained long-term operation in hostile plant environments. Local microprocessor controls and real-time data on component conditions can then be integrated with the plant computer for direct feedback into operations and maintenance activities. "Monitoring in itself will not improve plant availability unless it affects maintenance and operations decision making," Scheibel notes.

Just such an integration—the first at any coal-fired plant in this country—is being carried out only a few hundred yards from a sister unit that itself made history nearly 30 years ago. At Unit 2 of Philadelphia Electric's Eddystone plant on the Delaware River, EPRI and the utility have assembled a state-of-the-art diagnostic monitoring demonstration center not only to evaluate present monitoring systems and develop improved ones, but also as a focal point for utility training and technology transfer.

Unit 1 at Eddystone still holds the world record for the highest supercritical steam conditions ever achieved; planned life-extension work should give it another 22 years of service, "a remarkable achievement for a prototype unit," says Armor.

The 325-MW Eddystone Unit 2, also a supercritical plant, is earning a spot in the record books in perhaps a more important way: with virtually every major plant component permanently wired with sensors and feeding continuous data through a fiber-optic highway, operators and maintenance engineers will be able, for the first time and in real time, to observe the actual effects of operation on the performance and wear of critical parts and subsystems.

Performance Monitoring Options and Costs

The choice of a performance monitoring approach depends on the level of hardware and software investment a utility is willing to make and the degree of accuracy and precision desired in tracking heat losses. In addition to improved performance, the most extensive approach also offers equipment diagnostic monitoring for reduced maintenance and outage costs. The cost figures shown are rough orders of magnitude.

Approach	Cost ($000)	Comments
Use existing station instruments with new monitoring software	50–200	Uncertain accuracy and precision
Install dedicated temperature, pressure, and flow sensors for complete flow/energy balance	500–1500	Significantly improved accuracy
Same as above with on-line incremental heat rate dispatch	750–1750	Can track and recover true operating cost
Same as above with dedicated sensors for diagnostics	1000–2000	Increased savings in maintenance planning and scheduling

Armed with accurate, on-line diagnostic data, plant specialists are integrating the signals from several computer monitoring systems for display and analysis in a predictive maintenance diagnostic center. Special hardware and software interfaces have been designed to bring all the data from different computer operating systems under a common set of diagnostic display terminals.

Not only are maintenance specialists able to track key plant operating parameters along with the monitoring data in the diagnostic center, but operators in the control room have access to the same diagnostic displays alongside their traditional consoles. In addition, a technology transfer center nearby is expected to become a focal point for training a generation of utility maintenance staffs in on-line monitoring and predictive maintenance, providing the same real-time displays seen at other terminals in the demonstration center and in the plant control room. The first technology transfer course was held last June, covering acoustic leak detection for boilers, feedwater heaters, piping, and valves. Once the facility is completed, a dedication is planned for early next year.

"Never before have so many sensors and monitors been installed in a single plant," notes Scheibel. "This unprecedented on-line capability will be the basis for demonstrating and refining the kind of predictive maintenance program that may well be essential for keeping older plants running with high availability."

Many of the individual on-line monitoring systems installed at Eddystone had already proved their worth and potential for improving plant availability at other utility sites around the country. A photon-level tour along the Eddystone plant's fiber-optic data highway would reveal several highlights.

At over half a dozen thick-walled pressure components in the boiler itself, including headers, drums, and steam lines, a boiler stress and condition analyzer gathers thermocouple readings and continuously calculates temperature distributions and pressure changes.

Microprocessors programmed with material properties values and stress equations feed digital data streams onto the fiber-optic highway, either for observing how well key stress indicators such as creep and fatigue are staying within desired limits or for historical trend analysis. A performance monitor constantly tracks boiler and overall plant efficiencies and helps to optimize burner controls and soot blowers. On-line data from an acoustic temperature monitor for furnace gas temperatures help avoid overheating during startups.

Also in the boiler, a series of acoustic microphones stands sentinel outside the waterwalls, superheater, and reheater tubing for the broadband noise of steam leaks. Signals are filtered, amplified, and decomposed to sound alarms and even reveal the locations of impending failures for maintenance planning. The chemical balance of the water itself in the feedwater heater system is continuously monitored to limit corrosion damage and the frequency of acid-treatment boiler cleaning during shutdown.

At the power-producing end of the plant, turbines and generators are instrumented as well. A water induction monitor detects and signals the presence of heavy or wet steam to minimize blade and rotor damage. A sensitive vibration monitoring system warns of turbine rotor and bearing faults by revealing minute changes in amplitude and phase. With its data displays, operators can estimate the rate of component degradation, which can sometimes be minimized by altering plant operation until repairs can be scheduled.

Technology for on-line analysis of lubricating oil chemistry and bearing wear in pumps and large motors provides another path for early warning of something amiss.

Using surface layer activation with gamma-emitting isotope treatments, researchers and engineers are able to track the wear and solid-particle erosion of high-pressure turbine control valve disks as well as of blades and vanes. Several isotopes of cobalt, zinc, and manganese are embedded beneath the metal surfaces by means of a high-energy proton beam. As the components wear during operation, the activated particles are collected just downstream, where scintillation counters translate their readings into highly accurate wear measurements. (The low levels of radioactivity pose no risk to plant personnel.)

A turbine performance monitor similar to that used at Morgantown not only tracks the Eddystone unit's internal turbine efficiency but also provides clues to possible unseen steam leaks that can lead to accelerated wear. At the generator end of the turbine shaft, additional vibration monitors integrate data from dozens of sensors to analyze the frequency spectra for details of machinery resonance. Radio-frequency monitors outside the generator warn operators of arcing from broken windings in the core and the hot spots they cause that can lead to damage.

Each of the diagnostic monitoring devices deployed at Eddystone presents certain problems and issues of accuracy, calibration, and electronic integration with different plant computers. "The key is to explore and demonstrate how all the technologies can work together as part of a greater whole in a way that redefines the maintenance function and brings a true on-line predictive capability," explains Scheibel. Ultimately, the work will lead to detailed predictive maintenance guidelines that lay out for a utility how to

Utility Demonstrations of Equipment Diagnostic Systems

Many utilities, in cooperation with EPRI, are evaluating a variety of diagnostic techniques and systems for monitoring the performance degradation of key plant components, where problems result in frequent or prolonged outages. As the table indicates, the cost of diagnostic hardware is more than recovered if a monitoring system prevents even one forced outage.

Problem	Total Annual Forced Outages*	Average Hours of Full Outage*	Power Cost for One Outage ($000)*	Cost of Diagnostic Hardware ($000)	Technique	Utility
Turbine shaft cracking	90	984	6200	100	Vibration signature analysis	Florida Power & Light
Turbine blade vibration	270	708	4400	40	Acoustic-Doppler	Philadelphia Electric
Generator arcing	40	386	2400	25	RF signal detection	Texas Electric
Turbine water induction	15	363	2300	200	Ultrasonic sensors	Pennsylvania Electric
Turbine/boiler erosion-corrosion	1660	80	500	70	Surface layer activation	Dayton Power and Light
Boiler tube leaks	5230	65	406	90	Acoustic emissions	Baltimore Gas & Electric
Boiler creep-fatigue	30	54	338	200	Stress analyzer	Consolidated Edison
Rotating machinery damage	8730	43	269	300	Vibration signature–rotor dynamics	Philadelphia Electric, United Illuminating
Draft fan bearing failure	2190	33	206	50	Vibration/acoustic sensors	Pennsylvania Electric

*Outage data supplied by the North American Electric Reliability Council is presented as an industry-wide average based on the problem specified in the first column. Power cost assumes the purchase of 500 MW for the average outage duration at 1.25¢/kWh.

set up its own program, plan a maintenance strategy, and provide the necessary technical skills.

In the control loop

As more sensors and computer-based monitoring systems find application in coal-fired plants, the need for integration under a common control scheme increases. In some cases, the output data from one system represent an important process variable for another system. Moreover, the increasing use of computers for monitoring and process control brings new opportunities for automation, both in plant operations and in training personnel how to manage and make the greatest use of existing computer power. Computer-based expert systems using artificial intelligence techniques hold great promise in helping operators interpret the new data streams.

"Information and resource management are going to be critical aspects of plant operations in the future," predicts Murthy Divakaruni, an EPRI project manager. "We've reached the stage where electronic technology can be used throughout a plant. Now there is a major opportunity to tie everything together. The idea is to process and present data tailored to the needs of the end users and to avoid information overload."

Divakaruni, who directed EPRI projects to develop the Modular Modeling System (a powerful package of dynamic analysis models for nuclear and coal plants), foresees a time when such tools become part of on-line, multivariable plant controls, monitoring and adjusting key parameters under operator supervision according to preset limits. On the other hand, such integration can also open the door to advanced plant simulators, allowing operators and trainees to experience the dynamics of operation under realistic conditions or analyze the effects of different operating modes off-line.

In response to the trends in on-line monitoring and computerization, EPRI has several initiatives in fossil plant controls and automation. The early focus has been on developing a comprehensive R&D plan with broad industry input and producing guidelines for control system maintenance and retrofits. Farther off are expert systems now under development for such aspects of operations as boiler startup, plant cycling, heat rate analysis, and machinery diagnostics. Innovative control system designs are being explored under related EPRI programs for advanced coal plants of the future.

"We're also thinking ahead to the next century," says Divakaruni. "As coal-fired generating plants become more-complex process plants—coal refineries—utilities will need to understand better how to control the entire process—combustion, generation, emissions, by-products—in an integrated way.

"In addition to the hardware and software development, there are important issues of operator acceptance," Divakaruni adds. To address these issues, EPRI envisions an advanced technology transfer center that would combine all the on-line monitoring systems, such as those at Morgantown and Eddystone, with a flexible, state-of-the-art simulation and modeling capability.

A new face for an old technology

Coal-fired boilers powering steam turbines have been the mainstay of utility generating capacity since the dawn of the electric age over a century ago. In the last several decades, coal-fired plants have changed a great deal as new technology was added to control emissions to the environment. Now, with clean coal generating systems in demonstration and in sight for broad deployment, researchers' thoughts are turning toward advanced computers, electronic controls, and artificial intelligence as the final steps to realizing a second coal-based electric age in the next century.

But despite the present dearth of new plant construction, what is equally exciting as the vision of the future is that utilities are not waiting for the next generation of plants to apply modern electronics and data processing. Coal-fired plants are going high-tech to meet today's demand for electricity more efficiently and economically. The changes already under way and just around the corner will form a crucial bridge to the new systems of tomorrow.

"With future coal-fired power plants most likely resembling chemical process operations, decision making must become more heuristic and automated," says Armor. "EPRI's contribution will extend beyond developing monitors and software. We're already rethinking the role we can play in training and technology transfer. With Morgantown and Eddystone, we have poured the foundation for what may become a series of centers of excellence, pointing the way to the future while getting the maximum benefits from microprocessor technology today for the plants the industry still relies on." ■

Further reading

"Apply Automation to Diagnostics, Predictive Maintenance in Plants." *Power*, Vol. 132, No. 5 (May 1988), pp. 27-32.

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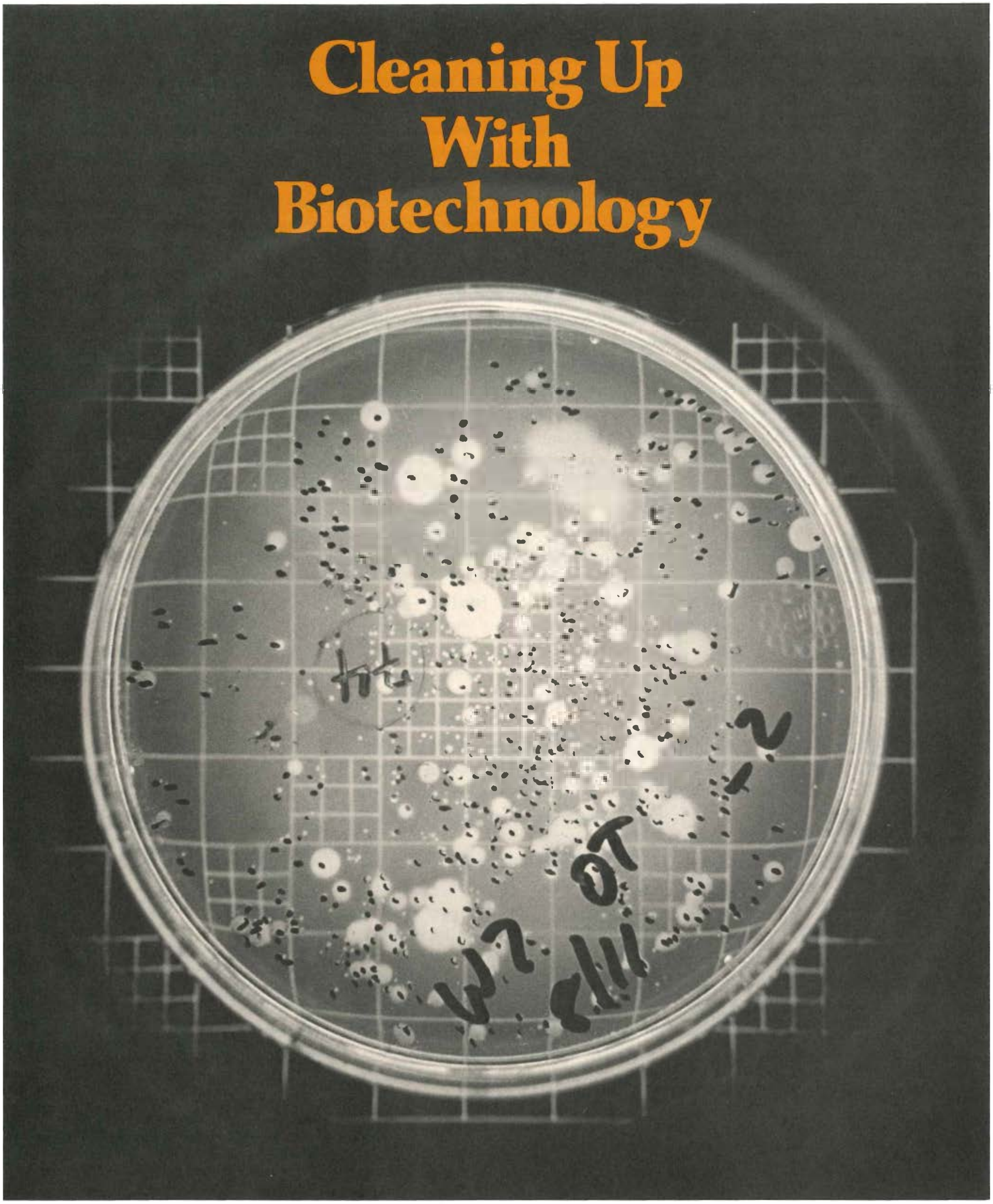
This article was written by Taylor Moore. Technical background information was provided by Anthony Armor, Murthy Divakaruni, Gary Poe, Robert Leyse, and John Scheibel, Coal Combustion Systems Division.

Cleaning Up With Biotechnology



The emerging science of genetic ecology is being pursued for in-situ treatment of toxic wastes. Using established principles of molecular biology for breaking down organic substances, the new technique avoids many of the technical and policy hurdles of genetic engineering.

The destructive capability of microorganisms can be startling. Virtually any organic material, from wood and coal to pesticides and PCBs, can be decomposed under the right conditions by a combination of bacteria and fungi. In any given soil sample, at least a few microorganisms probably have the particular genes necessary to control the decomposition of some specific compound, and nature has provided a variety of ways to multiply these genes and enhance their activity when the opportunity arises.

Some preliminary attempts have already been made to harness these natural processes as a means of destroying toxic substances in the ground. Contaminated soil may be plowed and sprayed with nutrients, for example, to stimulate the growth of bacteria that destroy a certain toxin. The results of such cleanup efforts have been rather unpredictable, however, since both the genetic variables and the environmental conditions that influence them are not well understood.

Now efforts are under way to study in more detail how environmental processes are controlled at the genetic level in microorganisms, especially bacteria. These pioneering efforts represent the first stage in the creation of a new scientific approach, called genetic ecology. Although still in its infancy, genetic ecology appears to hold great potential for leading to better ways of destroying toxic wastes where they lie, in both land and water. Other potential applications range from enhancing the biological gasification of coal while it is still in the ground to preventing microbially induced corrosion of condenser tubing in power plants.

"We're breaking new ground by taking existing concepts of molecular genetics and ecology and applying them to some pressing environmental problems," says Robert Goldstein, program manager in the Environment Division. "If we can enhance bacterial action to destroy toxic organic waste materials, then we can significantly lower cleanup costs. It's not going to be a panacea, but we may be able to lower costs by as much as a factor of 10. Within five years we should be able to provide utilities with practical tools they could use in bioremediation of some compounds at waste sites."

Collaborating with nature

Natural processes that break down complex organic molecules into harmless subunits usually involve many separate reactions, each catalyzed by a specific enzyme. In turn, production of each enzyme in a microorganism is controlled by the activity of a particular gene (see page 18). The group of genes that controls a specific sequence of enzymes is called an operon, which is turned on or off as a unit and may also be duplicated or transferred from one microorganism to another as a unit.

Learning how to enhance the natural duplication and transfer of operons that control the degradation of specific toxic materials is the ultimate aim of EPRI's present work on genetic ecology. Unlike genetic engineering, which involves the artificial manipulation of operons in a laboratory to create genetically novel microorganisms, genetic ecology seeks to understand and eventually control the behavior of microbial operons in a natural setting in response to environmental changes.

"The point is that we're going to use organisms already present at a site," says Betty Olson, a professor at the University of California, Irvine, who is the principal researcher in EPRI's genetic ecology work. "These organisms have a better chance of surviving than those you might create in the lab and then introduce to a site. In addition, I believe we'll encounter fewer regulatory problems with this type of experiment than if we tried to engineer new organisms."

Olson's general approach begins with determining the genetic potential of a particular site—that is, finding out how common the specific operons needed to break down a particular toxin are among microorganisms already present in that environment. Several microbial species may be involved; but out of a billion bacteria, Olson says, perhaps only a few hundreds or thousands may have the desired operons. Further, not all of the operons present may be turned on.

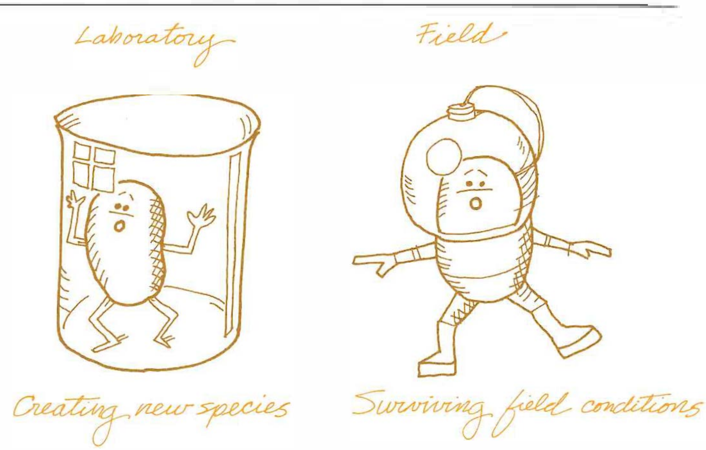
The next step is to find ways of causing the bacteria to make more copies of the required operons and to turn more of them on. Samples of soil from the site are taken to a laboratory and subjected to a variety of experimental conditions, such as the addition of different nutrients, changes in temperature, and oxygen enrichment—a process called microcosm studies. After varying periods of time, the effects of these changes on gene amplification and activity and on toxin breakdown are assessed.

Fine Distinctions in Biological Cleanup

Bioremediation is the use of microorganisms in the soil to render potentially toxic materials harmless. A very broad approach is usually taken, in which soil is plowed to increase aeration, then sprayed with water containing nutrients. Such treatment encourages microbial growth in general, and little attempt is made to select particular bacteria or genes for stimulation.

Genetic ecology attempts to refine bioremediation by identifying specific natural toxin-destroying genes and stimulating their activity. Soil samples are tested to see what genes are present in native microorganisms. Then environmental factors are modified—first in the laboratory and later in the field—to determine the optimum conditions for gene reproduction and expression.

Genetic engineering creates new microorganisms in the laboratory through the manipulation of genetic material; that is, genes are introduced into microorganisms that do not naturally contain them. This approach appears less promising than genetic ecology for bioremediation because of the likelihood of greater public resistance and the difficulty of keeping laboratory-created microorganisms alive under field conditions.



From the information gathered during these microcosm studies, a model is developed to predict the effect of producing similar environmental changes at the site. Actual field trials using these environmental modification techniques at the site will be conducted during the third year of EPRI's planned research. Three projects are getting under way this year. Two focus on degradation of specific hydrocarbons at town gas sites, and the other involves control of organic mercury compounds in lakes and streams.

Town gas sites

During the Gaslight Era, towns all over the United States manufactured their own gas for local consumption. In the East this gas was usually made by heating coal with steam; on the West Coast the thermal cracking of petroleum was favored. Both processes left behind a thick residue containing many potentially toxic materials. Most of these materials were simply buried—following the accepted practice of the time—and as electricity and natural gas became more popular during the early decades of this century, many of the sites where so-called town gas had been produced became the property of a new generation of utilities.

As more has been learned about the environmental and public health hazards that may be associated with such wastes, present-day utilities have begun to consider various options for cleaning up the old town gas sites they inherited. Conventional techniques—which usually involve digging up the wastes, followed by incineration or treatment with chemicals—would most likely be very expensive. Current estimates of the costs range from $50 million to $300 million per site, depending on the levels and types of contaminants.

Because techniques developed in genetic ecology may be able to reduce these costs substantially, one EPRI project is focusing on a group of toxic substances causing particular concern at town gas waste dumps—polycyclic aromatic hydrocarbons (PAHs). Although they are well known for their potential toxicity and carcinogenicity, PAHs can be rendered harmless by bacterial action.

The first compound selected for study was naphthalene, a two-ring PAH whose degradation by bacteria is well understood. Two operons—one with six genes, the other with seven—control microbial production of the enzymes that drive the 13 reactions required to transform a molecule of naphthalene into pyruvate, a common, harmless substance naturally found in plant and animal bodies.

Information gathered from genetic experiments related to naphthalene will be used to build a model for stimulating microbial destruction of PAH molecules with as many as five rings. David Gibson, a professor at the University of Iowa, is working on an EPRI project to identify and sequence the genes in operons capable of controlling destruction of heavier, multiple-ring PAHs, which can be the most toxic.

Two town gas sites, one in the East and one in the West, will be chosen for the sampling of naphthalene-destroying genes and the testing of environmental variables that influence their activity. The critical variables at the two sites may well differ, since the growth of soil bacteria is often limited in the East by cold temperature and in the West by lack of water. Other factors to be considered include the lack of specific nutrients—such as nitrogen, phosphorus, or potassium—and the effect of adding more oxygen to soil, perhaps in the form of hydrogen peroxide. The timing of environmental modifications may also be important, Olson says, since bacteria may be more likely to exchange genetic material during periods of freezing and thawing.

Mercury pollution

The second genetic ecology project is concerned with altering the transport of mercury in aquatic food chains. In some cases of high mercury levels in lakes and streams, the original cause is again quite old. Mercury was mined extensively in California during the Gold Rush, for example, for use in extracting gold from ore. More recently, however, concern has been expressed that mercury now being found in much lower concentrations in remote lakes may be the result of utility activity. Specifically, some scientists argue that some of this mercury comes directly from air pollution caused by burning coal or that its biological availability is increased at low pH, possibly as the result of acid rain.

Once in the water, mercury forms a variety of compounds, including methylmercury, which is easily incorporated into the bodies of aquatic animals. Not only is methylmercury highly toxic, it is also difficult for fish to excrete; they tend to accumulate it from the environment. The possibility that people might be poisoned by eating fish caught in waters polluted with methylmercury has become a growing public health issue.

The transformation of metallic mercury to methylmercury and back again is at least partially mediated by bacterial action. Again the genetic control system is understood well enough for researchers to assess the potential for reducing the toxic substance (methylmercury) by changing the environmental conditions that affect bacterial growth and genetic activity. In the case of aquatic systems, pH appears to be a key variable, as does the lack of oxygen that occurs at the bottom of many lakes during summer months. The presence of certain ions, such as calcium and sulfate, may also be important.

This project is being coordinated with other EPRI work that explores the transport and transformation of mercury in aquatic ecosystems. Project manager for that research is Donald Porcella of the Environment Division, who says, "Whatever Betty can find out will be useful to us as soon as it becomes available. We're not

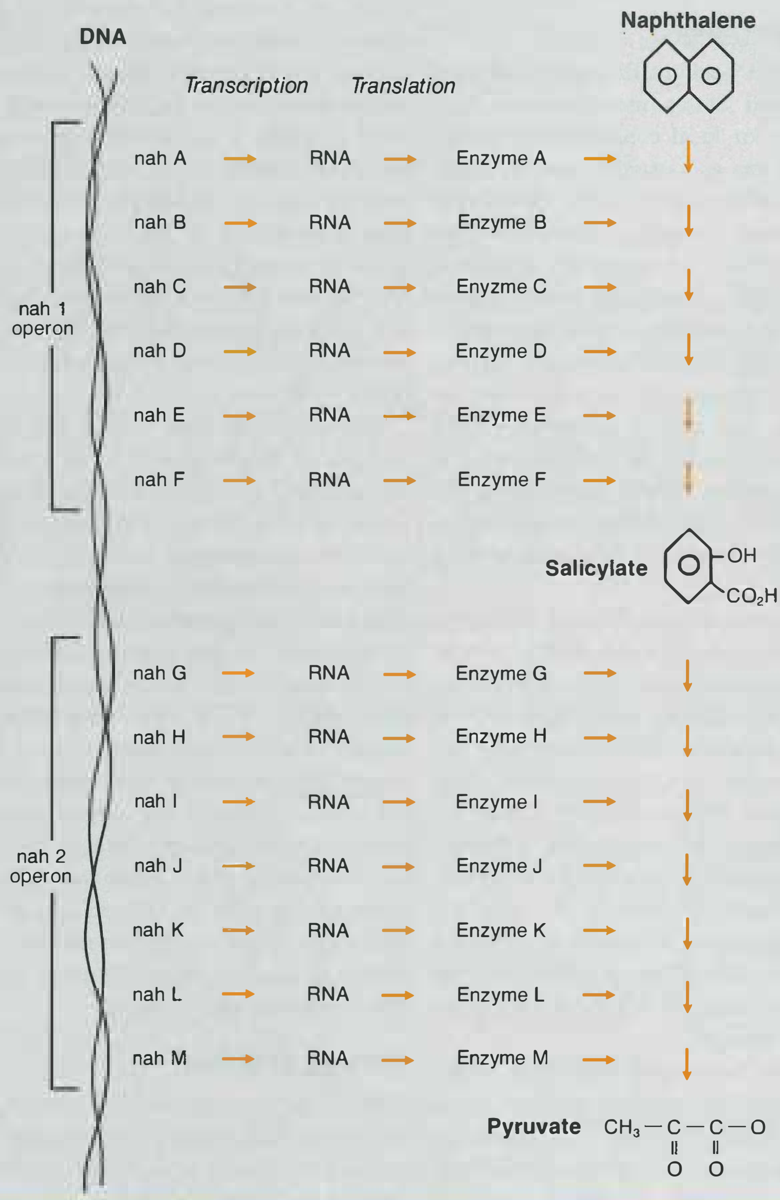
Primer on Genetics

The hereditary information of every cell in all organisms is carried by molecules of deoxyribonucleic acid (DNA). These molecules are composed of two long chains containing four kinds of building blocks, called nucleotides. The arrangement of these nucleotides represents a code, which tells the cell how to construct proteins. Two key steps in the building of a protein are the transcription of the genetic code from DNA to RNA, or ribonucleic acid, and then its translation into a sequence of polypeptides that make up the protein molecule.

Enzymes are large protein molecules that act as catalysts for most of the chemical reactions that take place in living organisms. For example, some bacteria can break down naphthalene to salicylate through a process of six reactions, each catalyzed by a specific enzyme. Similarly, salicylate can be broken down to pyruvate by another seven enzymatic reactions.

The sequence of enzymes involved in the degradation of naphthalene—and the corresponding sequence of genes that control their formation—is well known. The genes, labeled nah A, nah B, and so forth, occur in two discrete sets. The first set is called the nah 1 operon; the second is called the nah 2 operon. For the breakdown of many other organic materials by bacteria, such detailed gene sequences have not yet been identified.

In order to control the breakdown of naphthalene in contaminated soil, genetic ecologists must first determine the genetic potential of bacteria in the soil; that is, they must measure how frequently nah 1 and nah 2 operons occur in the natural bacterial population. This procedure involves matching DNA from the bacteria to radioactively labeled probes containing the desired operons. Next, an RNA probe is used to measure the rate of genetic expression—that is, to determine to what extent the bacteria are actually using their nah 1 and nah 2 operons to make enzymes. Once these two factors, the genetic potential and the rate of genetic expression, have been determined for a degradation process at a particular site, genetic ecologists can explore ways to enhance the process by modifying environmental factors. □



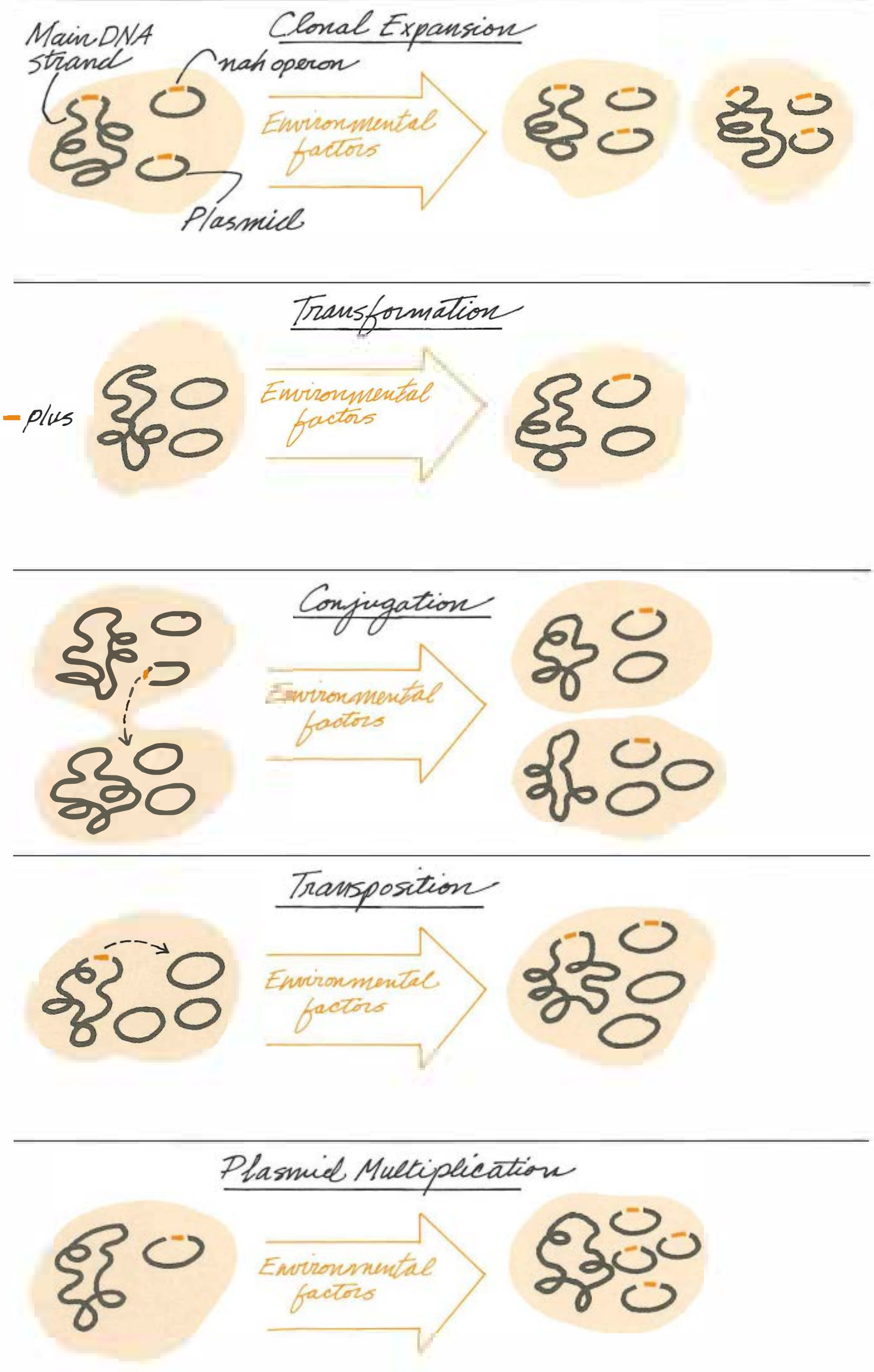
Genetic Ecology in Action

Genetic ecologists are exploring the use of environmental modification to enhance the degradation of toxic substances in soil by bacteria. This work includes experiments on small samples of soil, called microcosms, taken from the field site under study to a laboratory. Through such experiments, researchers seek to learn how to enhance the natural duplication and transfer of the genetic material that controls the degradation of a specific substance. The environmental variables being considered include temperature, moisture, nutrient levels, and the presence of oxygen (since most of the bacteria responsible for the breakdown of large organic molecules in soil are aerobic).

One of the simplest ways to increase the genetic potential at a site—that is, the occurrence of the gene groups, called operons, essential to the degradation process—is to increase bacterial growth in general. This approach, the one most commonly used in bioremediation, is based on the process of **clonal expansion,** by which bacteria divide to create new, identical organisms. When the bacteria with the relevant operons divide, the total number of these operons at the site increases. Some of the operons may occur on the main DNA strand (chromosome) of a bacterial cell. Others may occur on much smaller, generally circular DNA rings, called plasmids.

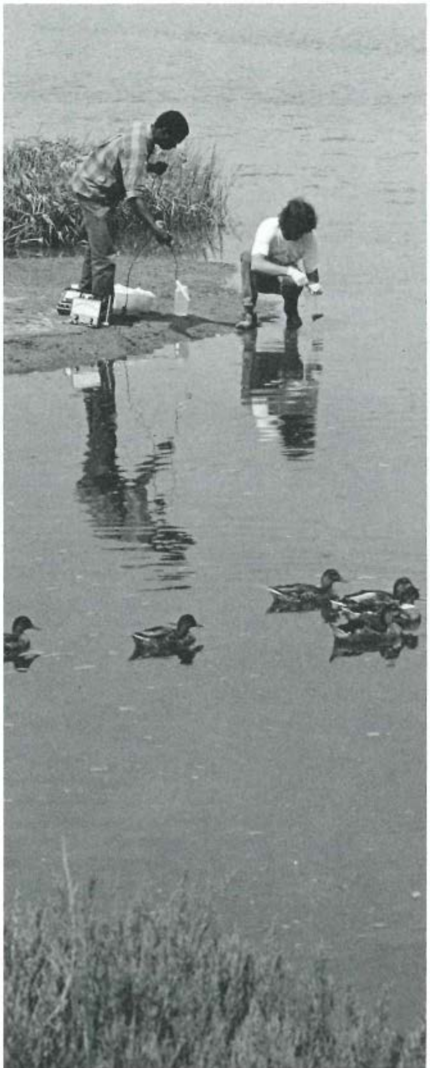
Genetic information is also transferred naturally between bacteria, under the influence of various environmental factors. One process, **transformation,** involves a cell's taking up free DNA segments, perhaps left over from other bacteria that have died. Another process, **conjugation,** occurs when genetic material moves from one bacterium to another while they are physically joined.

There are also processes whereby the number of operon copies within a single cell increases. During **transposition,** an operon is copied and moves onto one or more plasmids or onto the chromosome. During **plasmid multiplication,** plasmids divide independently of the cell, creating copies of themselves in the bacterium.



From Lab to Field

The new science of genetic ecology emphasizes collaboration with nature to eliminate harmful substances. First the established techniques of molecular genetics are used to identify specific toxin-destroying genes in soil bacteria. Then genetic ecologists study how changes in various environmental conditions—such as temperature, moisture, nutrient levels, and oxygen level—affect gene activity. This environmental manipulation is first conducted on containers of soil, or microcosms, in laboratories like that of Professor Betty Olson at the University of California at Irvine. Later it is duplicated in the field as part of a program of bioremediation.



sure which organisms are doing what, or which processes are the most important. Quite aside from the bioremediation aspect of genetic ecology, the information being generated can help us better understand a very complex process."

Sites include a reservoir near an old mercury mine in California, a pond and stream near Oak Ridge National Laboratory (ORNL) in Tennessee, and several remote lakes in Wisconsin. In the first two cases, bottom sediments appear to be a significant repository of mercury, with 1–13 ppm mercury being found in sediments at the California reservoir and up to 600 ppm at the Tennessee pond. (Mercury was used extensively at ORNL during World War II to enrich plutonium.) What relationship this sediment-bound mercury has to the level of methylmercury in the food chain will be a particularly important question for both sets of EPRI researchers.

The Wisconsin lakes present a different problem. Although mercury levels in sediments there are low, levels in fish are high enough to prompt warnings against their consumption. EPRI researchers hope to identify the source of this mercury.

Diverse reactions

Even while they speak enthusiastically about the potential of genetic ecology for helping to solve some intractable toxic waste problems, all those involved in the current work stress its exploratory nature and significant cost and regulatory uncertainties. Differences of opinion become particularly evident if one asks when utilities are going to be able to make practical use of the knowledge being developed by genetic ecology research.

"Right now," insists Professor Olson. "Some of our diagnostic techniques could already be used in conjunction with current bioremediation efforts." At sites where efforts are already being made to destroy toxic wastes by stimulating bacterial growth in general, she says, genetic assessment could easily be used to monitor the effectiveness of such work in terms of actual increases in microbial ability to degrade particular toxins.

On the other hand, John Maulbetsch, senior scientist in exploratory research, cautions that "it could be 20 years before genetic ecology becomes an established science. We're dealing with very complex systems and very sophisticated diagnostic tools." Nevertheless, Maulbetsch says, his program is providing funds for the genetic ecology work focusing on mercury because "if they succeed, we'll have not only a new cleanup technique but also a better understanding of how nature deals with contaminants."

Sy Alpert, EPRI senior fellow, is also skeptical. "Practical application of genetic ecology is highly dependent on the results of scientific work that is just getting started," he says. "I believe that the eventual costs and benefits are impossible to ascertain at this time."

Even if the research is successful, two barriers could slow its application, according to John Huckabee, program manager for ecological studies. "Initially," he says, "utilities may be reluctant to be first to try something this new, although the industry representatives we've talked to have been very receptive. Also, I'm concerned that the public may confuse this work with genetic engineering. We've seen tremendous fear that genetically engineered organisms would 'run away' in nature. Those fears shouldn't apply here, since we're not making anything new but rather helping organisms already there to do something better. But I believe the public needs to be educated well about the difference."

Others are more sanguine about public acceptance. "I hope this is not going to be a major issue, since we're not really adding new organisms to a site," says Chin-I Lin, a senior chemist at Pacific Gas and Electric Company. "This work is very, very important for companies, like mine, that have several town gas sites. You can't just hire somebody to clean up these sites. If the genetic ecology work is successful, it could solve many of our problems."

Such expressions of support from the industry are surprisingly frequent, says Ralph Perhac, department director for environmental science at EPRI, who sees at least three reasons for their enthusiasm. "First, I believe they're glad to see EPRI willing to take on high-risk new work that they couldn't afford to do themselves. Second, the utilities are beginning to recognize the shocking cost that would be involved in trying to clean up town gas sites using conventional means. And finally, there is still some time available to do the research. The industry is taking the lead on addressing the problem of town gas sites without waiting to have new regulations held over their heads."

On the issue of when utilities will be able to use some of the new techniques, Perhac takes a middle position: "I believe we're about five years away from first use, if all goes well. The real holdup may not be the complexity of the science, however, but rather a shortage of talented people. I suspect that many molecular geneticists are now working in large commercial ventures aimed at applying genetic engineering to problems of medicine and agriculture. Funding for genetic ecology is very small by comparison, and EPRI is emerging as a leading sponsor of this fledgling science." ■

Further reading

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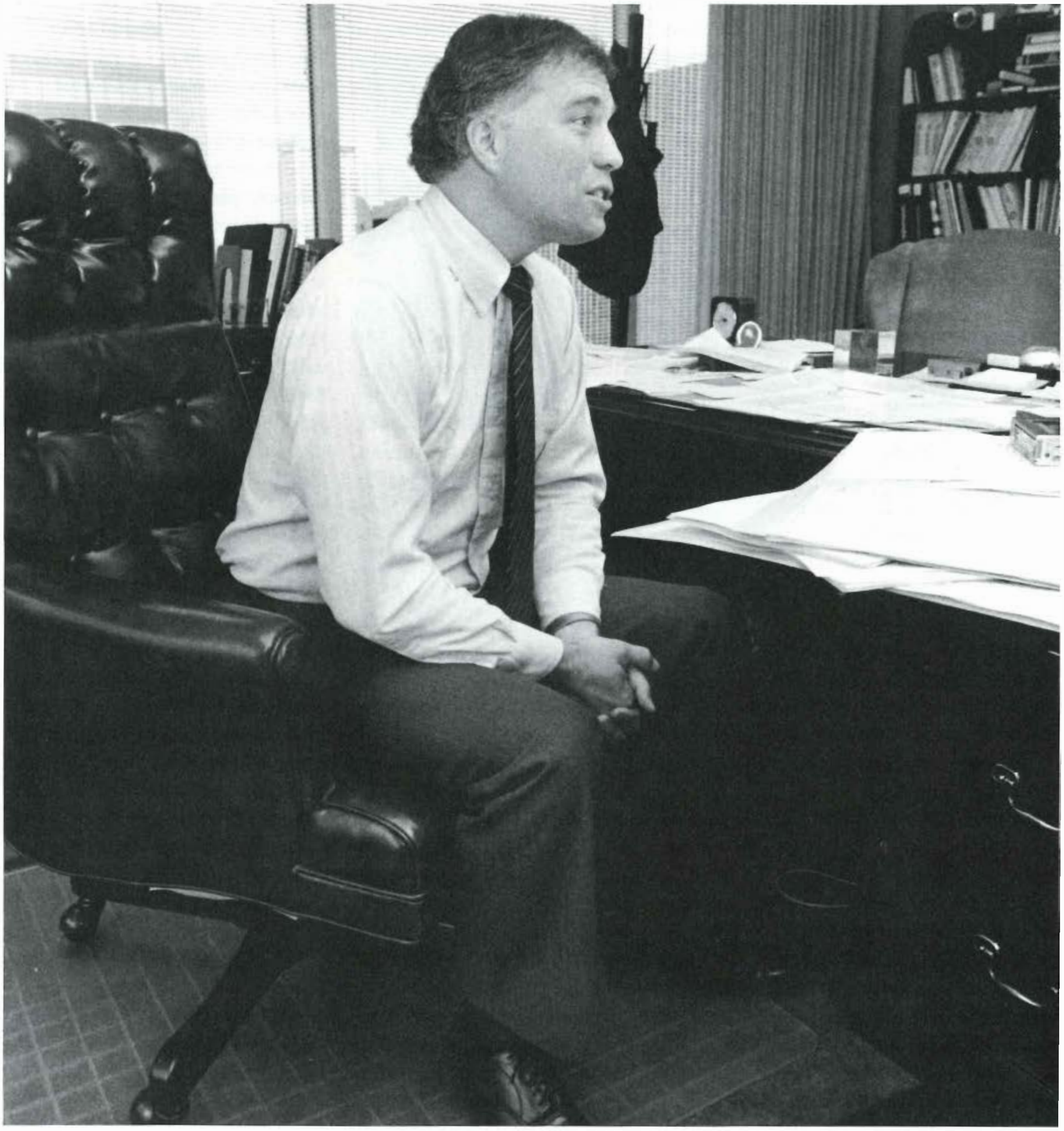
This article was written by John Douglas, science writer. Technical background material was provided by Robert Goldstein and Donald Porcella, Environment Division, and Betty Olson, University of California at Irvine. Additional information was provided by Ralph Perhac, Sy Alpert, John Huckabee, John Maulbetsch, and Conrad Kulik.



The current chairman of Ohio's Public Utilities Commission and member of EPRI's Advisory Council sees the synergy between government and business in steering technology: "I don't believe the market alone can put into place the kind of subsidies needed to make the system work to the advantage of society overall. Government can force a longer-term view."

TOM CHEMA:
Energizing the Business of Government

Tom Chema remembers exactly when politics caught his interest. It was 1958, and Ohio's longtime congressman Wayne Hays was running again. "A campaign worker was hiring kids at our school to pass out his literature," Chema recalls, "and he was paying a buck an hour. Pretty exciting stuff for a sixth grader. I was in it primarily for the money, but there was a campaign staff party after the election, and he invited this half-dozen kids. I was awed."

Hays was chairman of the House Administration Committee "when that position really meant something," Chema continues, "and I got interested in government. I would write to him, and he would send me information about bills I was interested in. I started reading American history, politics, and biography. And then, when John Kennedy ran for the presidency, I was hooked."

Today Tom Chema is chairman of the Ohio Public Utilities Commission, a job that he terms "absolutely fascinating, an opportunity to make a contribution, to really make a difference. The PUC probably touches the lives of more Ohioans than any other state agency. But we're largely invisible," Chema adds, which seems to suit him just fine "because I'm much more interested in government than I am in politics."

Chema is also one of seven utility regulators named by the National Association of Regulatory Commissioners (NARUC) to serve on EPRI's Advisory Council, a window to the world outside the electric utility industry. Through it EPRI gets illumination and fresh air from some two dozen men and women in such fields as conservation, education, labor, manufacturing, medicine, merchandising, science, transportation, and welfare.

Although Chema distinguishes politics from government, he doesn't distance himself from politics. He's in a clearly political position and counts it as a plus for his advisory role to EPRI. "I have the perspective of a regulator who is also involved with state government in general. The governor has had me involved in a wide variety of problems, from bank failures to search committees for other cabinet agencies, and at times as a surrogate for him."

Getting into government

Tom Chema's path from the neighborhoods of East Liverpool, where he distributed fliers for Congressman Hays 30 years ago, to Columbus, where he chairs the PUC from the 15th floor of a Broad Street office building today, has been reasonably direct. And, except for his time at Notre Dame, at Harvard Law School, and in the Air Force, it's nearly all been right in Ohio.

But barely, because East Liverpool is almost in West Virginia; in fact, Chema's father worked for 34 years at Weirton Steel, just across the Ohio River. And for his first two years of high school, Chema lived at a seminary school in Pennsylvania. The experience served him well. "You had to do your own laundry there, everything. You were self-sufficient; there was no mother to guide you."

He also covered a lot of ground academically. Returning to East Liverpool with only a handful of high school requirements still to complete, he turned to athletics and other activities. Politics became important. He won the junior and senior class presidencies, got into debate, and joined the Kiwanis International high school affiliate, called Key Club, of which he was elected chapter president and later an international trustee.

He kept his hand in after high school, too. He held class office for two years at Notre Dame, and while there he was able to work, in at least a small way, on an Ohio congressman's 1966 campaign—the first of some 15 election efforts that have involved him in the past 20 years. After graduating (magna cum laude) in history and being elected to Phi Beta Kappa in 1968, Chema paused at the landmark Democratic National Convention in Chicago and then went on to Harvard Law School—aided by an Air Force deferment that lasted until he passed the bar examination at the end of 1971.

Chema had married while in law school. Now came a year of Air Force duty, after which he and Barbara and their baby daughter returned to Ohio, settling in Shaker Heights, next to Cleveland, where they still live. Joining a law firm and the local Democratic Club, Chema began doing trial work and looking ahead toward the 1974 elections.

At that time, building on a friendship begun at the 1968 Democratic convention, he worked on Richard Celeste's successful campaign to be Ohio's lieutenant governor. The 1970s and early 1980s saw Chema working on two more Celeste campaigns (bringing Celeste to the state house in 1982), and also for Anthony Celebrezze (candidacies for secretary of state and attorney general), Howard Metzenbaum (U.S. Senate), and Walter Mondale (U.S. vice presidency), among others. Along the way Chema ran unsuccessfully for the Ohio senate in 1980;

“In the 1970s we burst the political bubble with Watergate, and there's a lingering cynicism about what motivates people in government. Now I think we've moved that cynicism to another professional group, technologists.”

and he would run for office again, he says, "but not because I'm interested in the running part!" He leaves the pure love of campaign dynamics to others, reemphasizing his preoccupation with the processes of governance.

Living in the limelight

In 1983, while still in law practice—and by then a partner—Chema was tapped by Governor Celeste to become executive director of the Ohio Lottery Commission. Chema easily acknowledges the relationship that brought him the opportunity, but he's equally clear that it was nothing he had sought. "I was the ninth lottery director in nine years! One of my predecessors was in jail, and I think only one other had left the lottery with his reputation truly enhanced."

Chema did things differently. "Our lottery—as in other states, I think—was seen by most people as a government agency that *happens* to be selling a consumer product. That's backwards. It's a *business* selling a consumer product, and it *happens* to be a government agency." Chema also did things fast. In 18 months' time, he took the lottery's gross sales from $400 million to $850 million. (The trend continues: $1.2 billion today.)

Another thing Chema did fast at the lottery commission was learn. He came away with a good grasp of the organizational planning, goal setting, and strategizing needed for business success—and a fair certainty they'd be useful in government work. He didn't have to wait to find out; in fact, he left the lottery commission to accept appointment as Public Utilities Commission chairman in January 1985.

Governor Celeste wanted the PUC to be more of an initiative body, and Chema has responded with marketing moves from his lottery experience. "We've opened ourselves up to the consumer groups in our constituency. We hold hearings across the state on every important issue before us. We try to make ourselves accessible. I do a radio talk show at least every other week. I get speaking engagements at service clubs. All to let people know what we're doing and why."

Slowing a bit and taking a breath, he determinedly concludes, "I think public input has had a very positive impact on us. And it has dramatically improved our credibility." Chema's earlier claim of invisibility for the PUC thus seems contradictory; but upon reflection it seems to hinge on the irony that good public service is seldom noticed, while scandal hits the headlines every day.

Most of all, Chema calls attention to the PUC's long-term policy-oriented way of thinking, "a distinct plus in the way we do our business. Most of our work, and our most important work, is quasi-legislative. We were established by the legislature to substitute for them in what had been their role—setting utility rates, setting transportation policy."

Chema dramatizes his point with the image of courts that review historical facts and make judgments about who was right and who was wrong—in the past. "What *we* do is look at those historical facts to determine what policy is needed for the *future*. In our important decisions, even including rate cases, we're not talking about the earnings a company should have had last year. We're talking about what they ought to be able to earn in the period ahead."

As an example of policy work, Chema refers to Ohio's new electric utility holding company act, passed in the spring of 1986, responding to the proposed affiliation (since completed) of Toledo Edison and Cleveland Electric Illuminating within the new Centerior Corporation. "We didn't want to create a paperwork jungle for the people at Centerior, but we did want to make sure we still had jurisdiction over the utilities in their new setting—matters of the uses of utility funds, diversification, where their assets can go, dividend policy, that sort of thing.

"I convened the companies—and interested consumer groups—in a conference room here. We got to basic agreement on the outlines, and then we went hand in hand, taking the lead at the legislature, proposing the bill. We got it through both houses in about two or three months and had it signed into law before Centerior came into being."

Family and technology ties

Enthusiasm carries Tom Chema through distance as well as through time. Being PUC chairman has meant a 150-mile weekly commute between Shaker Heights and Columbus. He leaves home at 5:00 in the morning most Mondays and returns Thursday nights, saving his northern Ohio field work for Fridays.

The Chemas thoroughly considered this regimen ahead of time, particularly since Barbara, with a doctorate in nursing, works in a neonatal intensive care unit and is on the clinical faculty at Case Western Reserve. "Barbara and the kids didn't want to move. She enjoys her work and they really liked their schools. Also, I travel so much," Chema adds, "that even if we had moved to Columbus, we might be together only one more day a week." He quickly catches himself on the rationalization. "I don't think we foresaw how long it might last, and it does put a strain on us; it's harder for Barbara than for the kids."

Brightening a bit, Chema speaks of a warm relationship with his children. "We still like to do things together. Christine is 16; I took her in for her first driver's license this summer. Stephen is 13; I've taken him with me on a few business trips, where he's enjoyed being included in small ways—just as I was many years ago.

"Summer is an easy time," Chema adds, "because the kids and I are avid baseball fans and we get to see the Indians play a lot. Baseball games are a wonderful thing to do together. Not like football, where you have to be on the edge of your seat every second. Baseball is a leisurely thing and there's time to talk."

Some of Chema's frequent travel stems from his own PUC policy on public contact: at least one day a month visiting energy users to talk about their utility service and their perceptions of the utility industry. Chema enjoys the exposure to a range of industries and their technologies—reminiscent of his years in product liability litigation that taught him about roofing materials, artificial heart valves, fans in fossil fuel power plants, and the spiral welding of steel pipe. "You know, right after one medical malpractice case, I was convinced that I could excise a colloid cyst from the third ventricle of a person's brain!"

But talking of his interest in technology turns Chema serious again. He worries about what he calls a burst in the bubble of technology—Three Mile Island, Chernobyl, the Challenger. "We're always looking for certainty," he says, "something to hold before us. Since World War II it's been technology. No problem was too great if we put our minds to it. And there were two areas we held up as being really the best. One was the space program and the other was nuclear power"—Chema is even more specific—"the safety side."

He sees a subtle but profound consequence of the internationally famous accidents, a distrust of technology as a whole. It doesn't show up in polls, Chema admits, but he sees it in a skeptical attitude toward technological matters. "In the 1970s we burst the political bubble with Watergate, and there's a lingering cynicism about what motivates people in government. Now I think we've moved that cynicism to another professional group, technologists."

Advisers who question

Government in general, regulatory policy in particular, and energy technology all come together for Chema in his EPRI Advisory Council membership, "my most significant extracurricular activity." As a utility regulator, he welcomes his insights from Council meetings as some-

"Our most important work is quasi-legislative. We were established by the legislature to substitute for them in what had been their role—setting utility rates, setting transportation policy."

"

Especially where new nuclear power plants threaten a sharp increase in rates when they come on-line, users are saying, 'Regulation hasn't worked to keep prices where we want them, so let's have competition.'

"

thing to share at home. "I try to circulate brief reports back to the electric utilities in Ohio, the companies in our jurisdiction."

The Council's main value for EPRI is in broadening the view of the Board of Directors—"external stimulation," Chema says, "regarding considerations beyond the purely business-related concerns that naturally occur." He cites the Council's urging that more budget, time, and effort go toward exploratory R&D because the federal government is faltering in its support, and that role must be taken up by others.

But again, with the electricity business as slow as it is (some industry vendors also are letting go of their R&D), where are the resources to come from? Chema alludes to the possibility of even more "networking" of R&D budgets—cooperation in a larger context than the EPRI membership circle alone. He points to the established practices of research cofunding and cost sharing, to EPRI's new overtures to universities, and to such joint initiatives as the Center for Materials Fabrication at Battelle, Columbus Laboratories, in Ohio.

Most of all, though, Chema points to the unique nature and value of EPRI itself. "If it didn't exist, we ought to invent it," he says, urging the point that all electric utilities should be members of EPRI and thus lend their support to its industrywide R&D program. Closer to home, he thinks particularly of American Electric Power, a nationally prominent utility headquartered in Ohio. "There's something about having a tangible stake in the effort," he muses. "If AEP were a member, its own R&D would be even more valuable."

Turning to the Advisory Council's special value as a questioner, Chema says there is always the possibility that corporate boards and their advisory committees may inadvertently come to reflect what the executive management already believes. "And the problem isn't limited to organizations such as EPRI," says Chema. "It's true for all publicly held corporations.

"I remember a 1952 article in the *Columbia Law Review*—one of FDR's brain trusters arguing that from a legal perspective, the managers of corporations should be treated as the owners, not the stockholders. His reasoning was that the crux of ownership is control, and control lies with the managers."

Chema volunteers that the management-led "group think" phenomenon also occurs in government, and he points to the paradox that some advisory groups are created specifically to avoid it. What, then, is the adviser's practical response? "The first thing is to recognize what may be going on and interject a healthy dose of individual independence. Don't be intimidated into not asking questions that seem less than intelligent."

Making regulation compete

Competition preoccupies utilities today and has implications for their ability and willingness to cooperate in R&D. The subject therefore comes up in EPRI's management and advisory deliberations. It's knotty for electric utilities, Chema believes, because much of the concern isn't directly with other utilities but is over "third parties"—independent generators, cogenerators, even customers. Deregulation thus becomes part of any discussion.

"In Ohio, at least, it is some end users who are talking the competition game," Chema says, "large industrials claiming they could get lower rates if there were competition, towns wanting to 'municipalize' utility service because they think rates are too high. Especially where new nuclear power plants threaten a sharp increase in rates when they come on-line, users are saying, 'Regulation hasn't worked to keep prices where we want them, so let's have competition.' "

Chema interjects what he thinks is a realistic scenario from recent history. "It can be argued that it was virtually impossible for some nuclear plant owners to change their minds after getting started. Say we're back in 1980, and they've spent \$2–3 billion on a plant but realize they no longer want it. What are the options?

"If they abandon it, they recover zero and their net worth doesn't nearly cover the liability. If they finish it, it's like rolling the dice: there's a chance of getting at least *some* of the cost into the rate base. From a management standpoint, is it imprudent to roll the dice?"

Chema's example dramatizes his conviction that competition, deregulation, and nuclear plant cost recovery are separate issues. "This pressure for competition, and its emphasis on deregulation, is a surrogate, I think, for a legitimate complaint that the regulatory process didn't deal very well with a number of multibillion-dollar plants. We regulators need to face that power pricing problem head on. But don't insist on changing the system; that's the wrong war."

Turning his attention to deregulation alone, Chema says that what is described is actually dis-integration, "taking a vertically integrated industry and lopping the top of it off"—separating power generation from power delivery. He has no quarrel with individual utilities and states that want to pursue that course, but he is uneasy with pronouncements from the Federal Energy Regulatory Commission in Washington that seem to encourage it across the board.

As a PUC chairman, Chema firmly believes in regulation at the state level. Electricity service is such an essential that government must be involved, one way or another, in regulating the industry. "I don't believe the market alone can put into place the kinds of subsidies—and I don't think that's a dirty word—that are needed to make the system work to the advantage of society overall."

Chema points to the specific example of R&D, which the market doesn't assuredly allow for. "The market puts pressure on the short term; you look at next quarter's bottom line." The statement takes him back to Ohio PUC policy. "Government can force a longer-term view, and one of our premises is that our decisions today have long-term impact. We must understand our work well enough to figure out what that impact will be." Chema smiles. "I don't want someone 10 years from now to be saying about me the kinds of things that I think about the guys who sat here 10 years ago!"

The next part of his career

But why should Chema really care? Where does he expect to be 10 years from now? What does it really mean that he's 42 years old, has held two state appointive posts in five years, and has worked on 15 Ohio electoral campaigns? The answer comes quickly. "Well, for one thing, I never want to be a campaign manager again unless the candidate is running for the White House!

"The second thing," he says levelly, "is that I'll continue to be politically involved. I'd like to hold elective office, but I have no grand design for getting there. I'd like to be attorney general or governor of Ohio someday. I think I could make a contribution in either role, and I'd like to try."

Chema tempers his straightforward ambition with a deep conviction. "Politics and government are one part of my career, but I don't want to spend 30 or 40 years at it. That would be a mistake for me, and speaking generally also, I think it's a mistake. One reason for our cynicism about politics is that we have too many professional politicians. We need more citizen politicians, people in public service for just a *part* of their careers, willing to devote five or ten years to government."

If Tom Chema, head of Ohio's Public Utilities Commission, regulates his own career in that fashion, Ohio will probably be well served. ■

This article was written by Ralph Whitaker and is based on an interview with Tom Chema.

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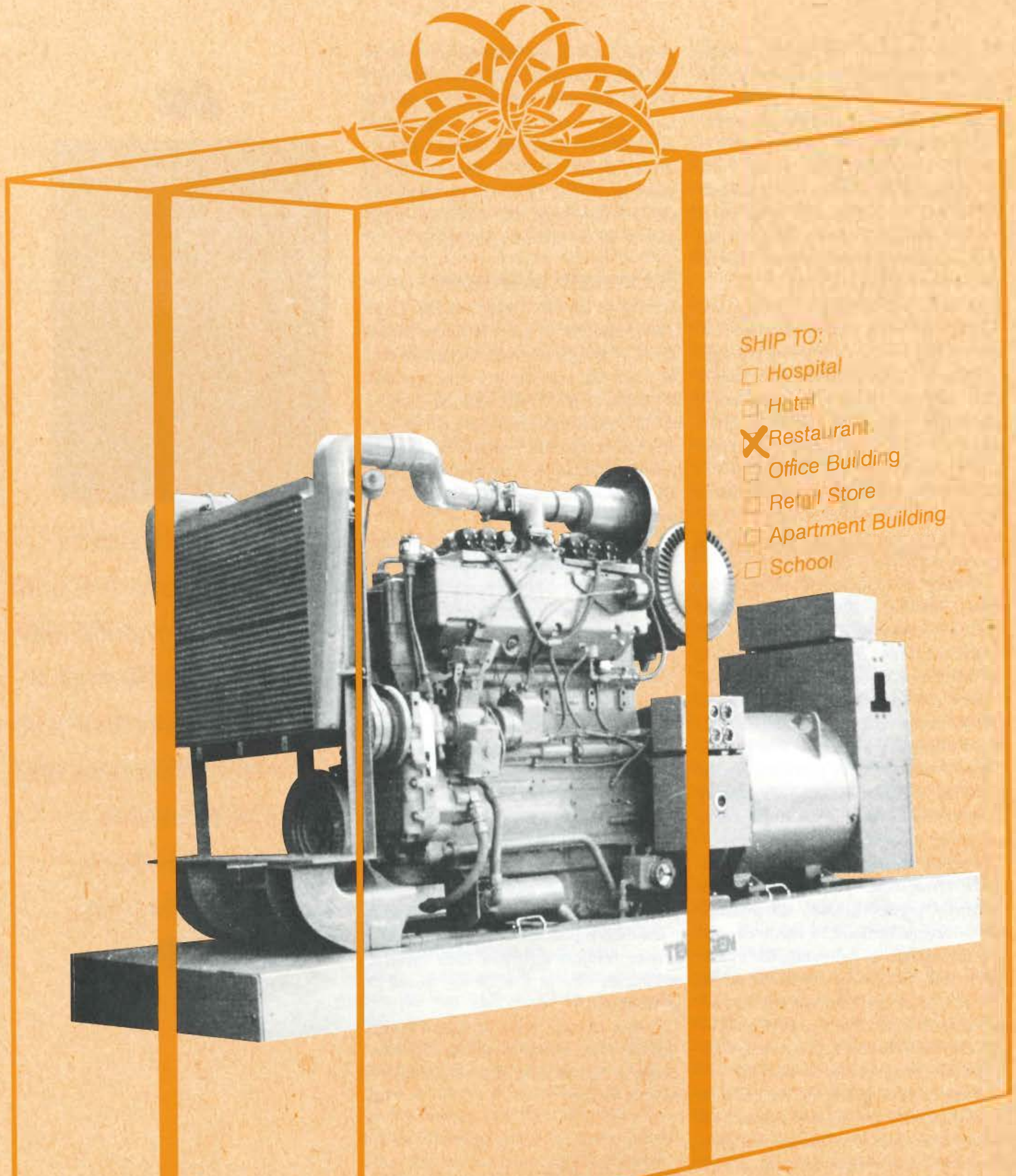
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The Challenge of Packaged Cogeneration

A battle is shaping up in the commercial sector, with packaged cogeneration units and high-efficiency electric technologies competing head to head as cost-saving energy options.

Owners of such commercial facilities as office buildings, health clubs, and fast-food restaurants face an increasingly complex decision when they try to lower energy costs. On the one hand, they are being offered small, standardized cogeneration systems that can supply much of a building's electric power while also providing thermal energy for hot water or space conditioning. On the other hand, new, high-efficiency electric equipment is available that can often reduce energy consumption with a much lower investment of capital.

Which of these alternatives better suits a particular facility depends on several factors, including electricity and gas rates, daily hours of operation, the need for cooling or refrigeration, the availability of maintenance personnel, and a variety of financial considerations. It is often difficult for the customer to assess these factors, particularly because of the limited availability of performance data on the relatively new "packaged" cogeneration systems.

"EPRI studies indicate that when packaged cogeneration systems are compared with high-efficiency electric alternatives, a commercial facility will usually do better with the electric equipment, in terms of meeting its overall needs," says Arnold Fickett, department director for end use in the Energy Management and Utilization Division. "But the economics of both types of equipment are highly application-specific. Our aim is to provide utilities with the data and analytical tools they need to help their commercial customers make the comparisons for their own business situations. EPRI is also deeply involved in developing advanced end-use electric technology."

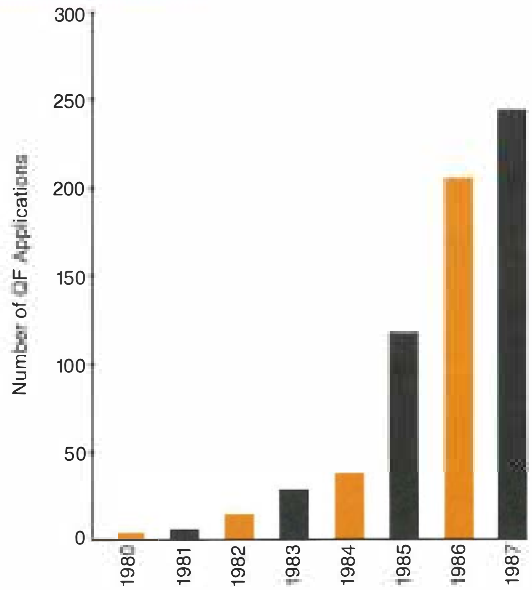
Competition grows

Cogeneration is the sequential production of electricity and thermal energy. Until recently, cogeneration systems were economical only for large industrial plants, such as paper mills or oil refineries, where the steam produced for primary plant processes could also be used to generate electricity. In commercial buildings, the priorities are reversed—electricity generation is the primary function of a cogenerator, with excess heat then used for other purposes, such as space conditioning.

Cogeneration became cost-effective for commercial facilities with the development of a new type of relatively small, self-contained unit. Such packaged cogenerators are factory-assembled from standard components and mounted on skids for ease of installation. Most have generating capacities of less than half a megawatt, compared with an average of

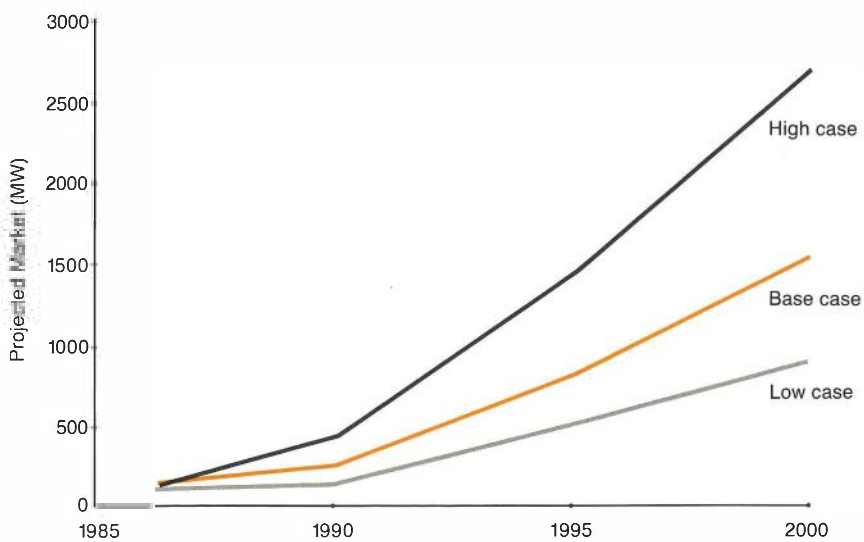
Businesses Show Interest

The number of qualified-facility (QF) filings received by the Federal Energy Regulatory Commission for small cogeneration units (less than 500 kW) has grown dramatically in recent years. While this is not a good measure of actual installations—many filers decide not to pursue the option—interest has clearly burgeoned since 1980.



Projecting the Market

Market forecasts indicate that packaged cogeneration units are likely to achieve substantial penetration of the U.S. commercial sector by the year 2000, with high-end estimates of up to 2700 MW of installed capacity. Still, large industrial cogen units already add up to about 20 times that capacity, and these custom-built giants are expected to remain the main focus for cogeneration.



40 megawatts for industrial cogenerators. A commercial customer generally selects a packaged system that is sized to meet the baseload electric and thermal requirements of a particular building.

Most packaged cogeneration systems are driven by commercially available reciprocating engines that have been converted to burn natural gas instead of diesel fuel. Electricity is produced by a generator driven directly by the engine; heat exchangers recover the cogenerator waste heat for use in the building—usually to produce hot water. For some applications, an absorption chiller is attached to the unit, enabling it to provide air conditioning or refrigeration. The cogenerators are designed to operate unattended, using fully automatic microprocessor controls.

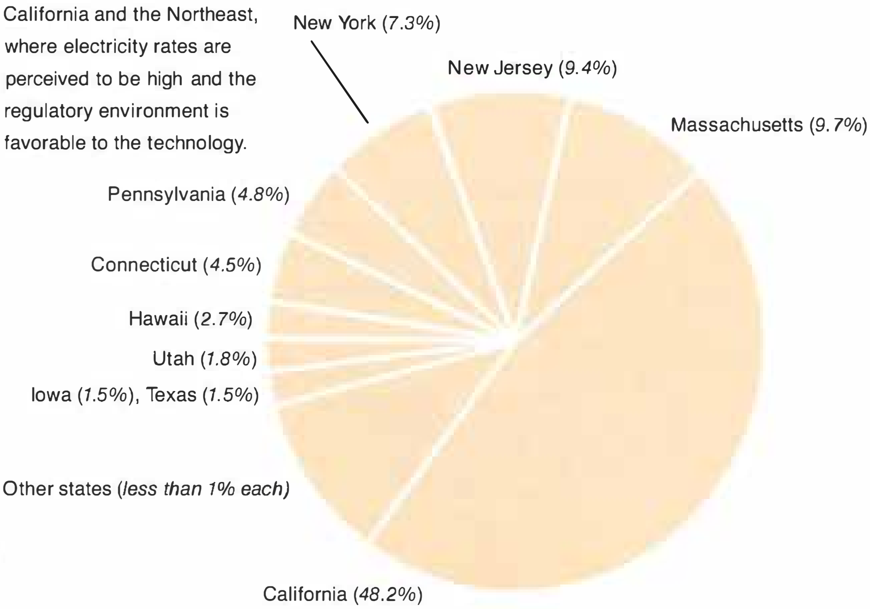
Although the total generating capacity represented by packaged cogenerators is still relatively small, the number of permits filed with the Federal Energy Regulatory Commission (FERC) to install such systems has been rising rapidly for several years. Such growth concerns many utilities because although the cogenerator serves the building baseload, the utility must still provide electricity during the most expensive (peak) periods of demand. The utility is also required to supply full backup power when a cogenerator unit is down.

"Packaged cogeneration is threatening what have previously been safe markets for electric utilities—lighting, space cooling, and refrigeration in the commercial sector," says Fickett. "By taking away the baseload, such cogeneration lowers utility revenues and causes higher electricity rates for noncogenerating customers."

Under provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), utilities must also purchase power from qualifying cogenerators if it is offered. Most small commercial facilities, however, are not expected to take advantage of this requirement. Commercial establishments are interested primarily in cutting their energy costs, not in generating

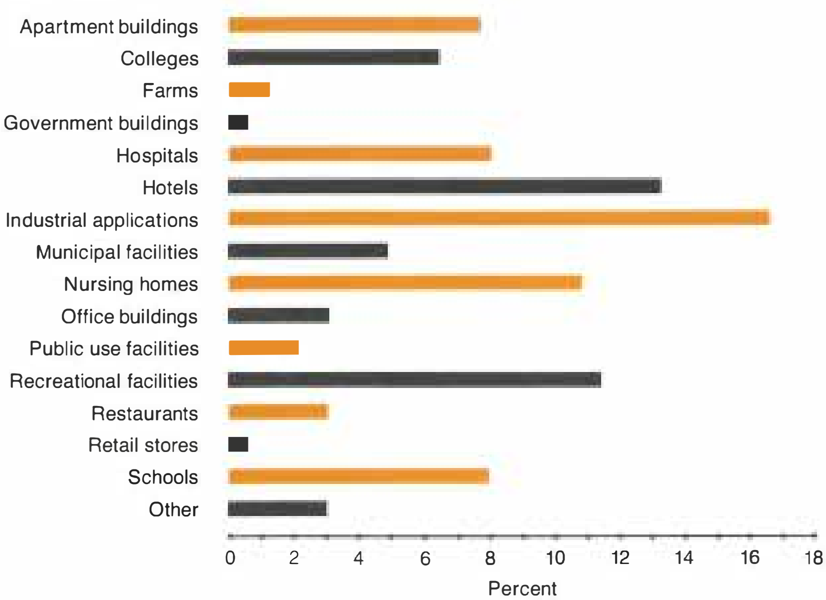
Commercial Cogen by State . . .

Packaged cogeneration units are selling best in parts of California and the Northeast, where electricity rates are perceived to be high and the regulatory environment is favorable to the technology.



. . . And by Site Type

A survey by Synergic Resources Corp. shows that packaged cogeneration systems are currently favored most by light industry and by commercial facilities with large buildings or complexes, such as hotels, nursing homes, and hospitals. However, the market for small cogeneration units is far from mature, and the distribution could change considerably as sales expand.



and selling surplus electricity as a business sideline. Utility buyback rates are often too low to justify cogenerators' operating in this mode; this is especially true where time-of-use rates are in effect, since a cogenerator's off-peak period (when it has electricity to sell back) is likely to coincide with the utility's off-peak period, when electricity is least expensive to generate.

Comparing the alternatives

Does cogeneration make good economic sense for the commercial sector? Yes and no. Replacing conventional equipment with packaged cogeneration systems can, as promoters claim, save on energy consumption. But the same is true when advanced, high-efficiency electric equipment is installed instead. Such equipment includes integrated heat pump systems for space conditioning and water heating, thermal storage systems for inexpensive off-peak heating and cooling, high-efficiency chillers for air conditioning applications, and multiplex refrigeration equipment designed specifically for the needs of supermarkets.

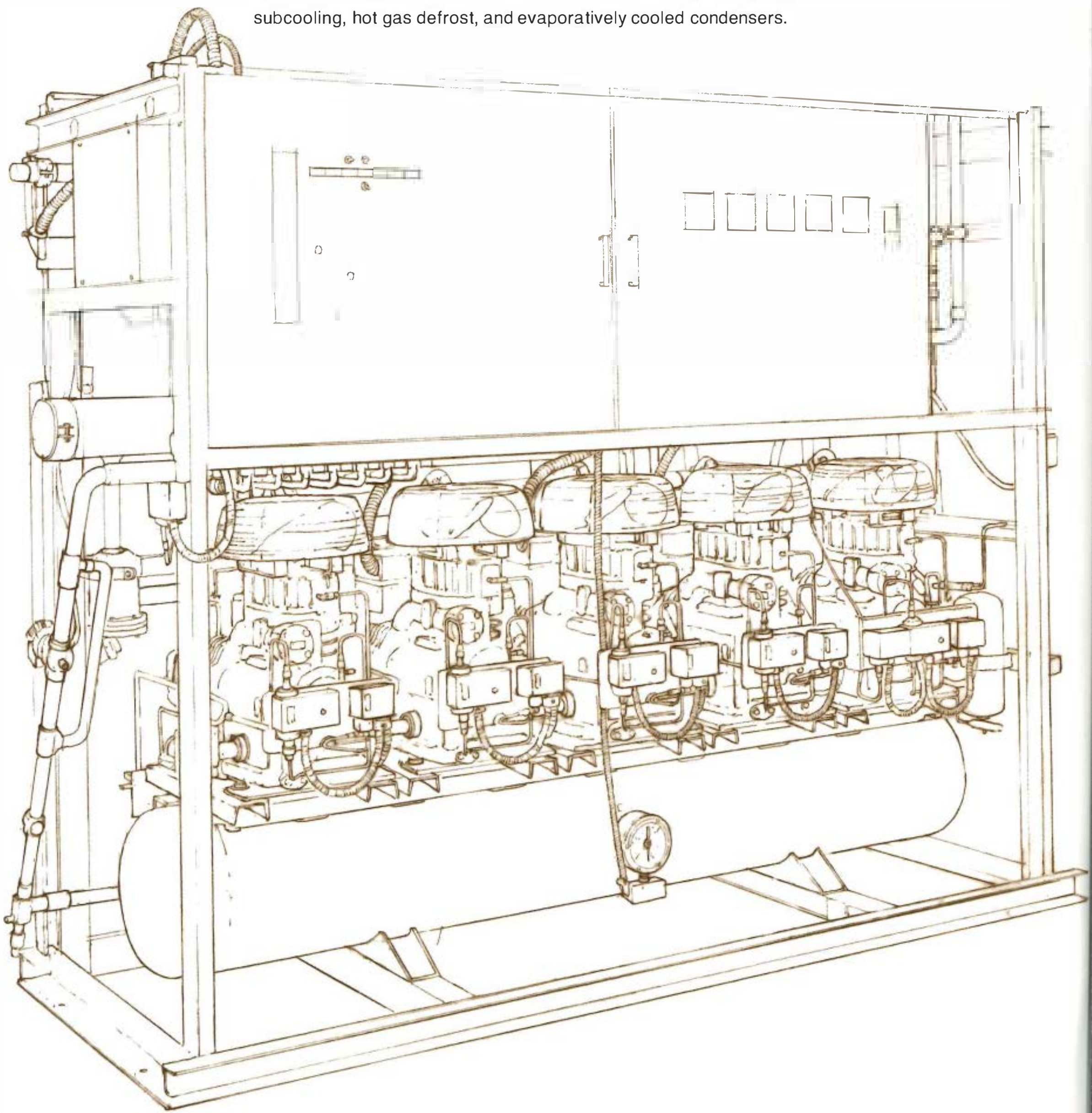
Comparing cogeneration and high-efficiency electric alternatives is difficult because they represent fundamentally different approaches to satisfying commercial energy needs, and a prudent purchaser must look far beyond simple efficiency figures to make a choice that can be lived with. Ordering a packaged cogeneration system means you are essentially buying your own power plant. You must find dedicated space on the premises for a rather large piece of equipment, buy your own fuel, arrange for your own maintenance, and deal with your own outages and repairs. These factors alone convince many commercial concerns that they don't want to be in the power generation business, that they prefer to rely on the hassle-free, "transparent" service provided by a utility company.

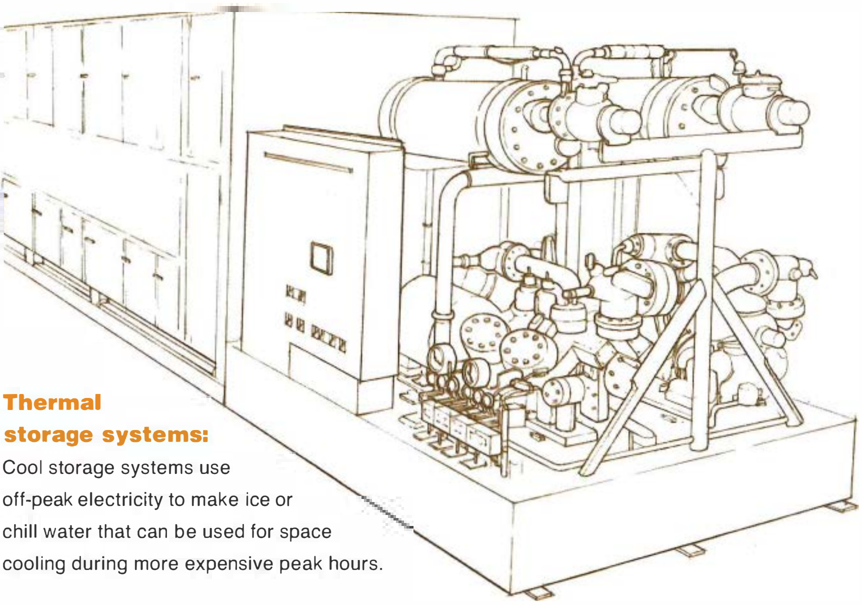
Operating costs and capital costs are also critical factors. The current low

Alternatives to Cogeneration

A wide range of high-efficiency electric equipment is currently available that can offer the commercial customer considerable savings on energy bills at a relatively low capital cost. EPRI case studies have shown the electric technologies to be competitive with packaged cogeneration systems under a variety of fuel cost scenarios.

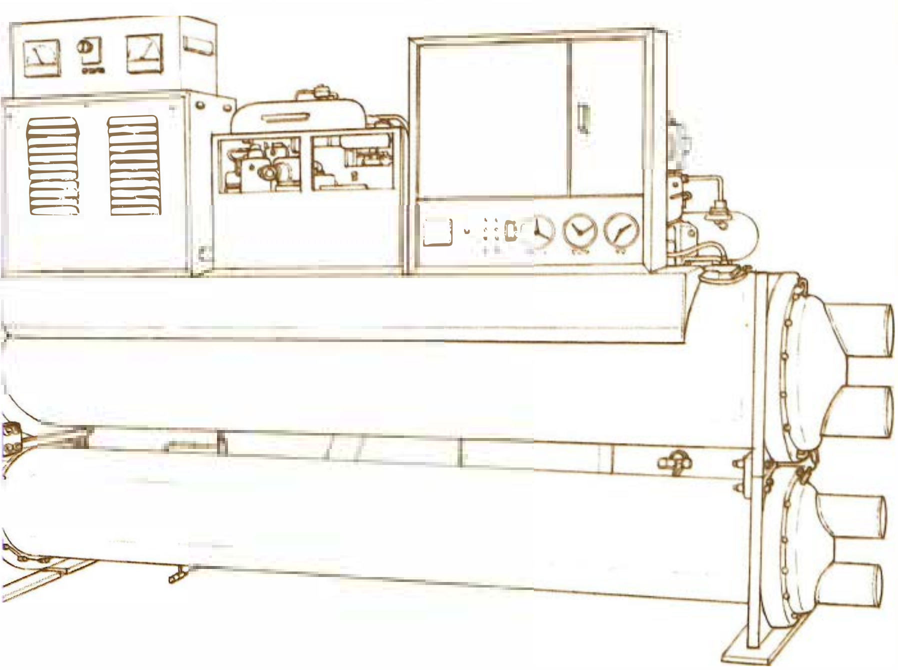
Supermarket refrigeration systems: State-of-the-art energy-efficient refrigeration equipment can reduce the energy required by supermarket compressors by 20–35%. The equipment includes such advanced features as floating head pressure, multiplex compressors, subcooling, hot gas defrost, and evaporatively cooled condensers.





Thermal storage systems: Cool storage systems use off-peak electricity to make ice or chill water that can be used for space cooling during more expensive peak hours.

Electric chillers: Space cooling loads can be served by reciprocating chillers in small buildings or by centrifugal chillers in larger applications. Heat recovery equipment can be combined with the chillers to provide water or space heating.



prices for natural gas can give cogeneration systems a strong edge in operating costs in service areas where electricity rates are high. In some of these cases, operating cost may become the deciding factor. But in many cases it's the capital cost of the equipment that makes the bigger difference. In virtually all cases, installing a packaged cogeneration system is significantly more expensive than upgrading a conventional system with high-efficiency electric equipment—and in some cases the cost ratio is as high as 20 to 1. Installed costs for cogeneration systems range from around $75,000 for a 60-kilowatt unit that will serve an athletic facility or a small hotel to nearly $700,000 (including the cost of absorption chillers) for a 500-kilowatt hospital system.

The payback period for such a capital investment is the most important consideration for many businesses. A large, long-term investment to achieve incremental savings in energy costs simply doesn't make sense for some commercial enterprises, especially when that money could be put to better use in improving the business's main product or service line. Most companies are looking for a payback period of no more than two years, and few can afford to wait for a four-year payback when the capital outlay is high. The significantly lower cost and correspondingly short payback times of advanced electric alternatives can make such equipment very attractive to risk-averse commercial customers.

Other decision factors are application-specific. One of the most important factors in determining cogenerator economics is the number of hours a day a facility is in use. Cogeneration systems must be run nearly continuously to be cost-effective. Thus cogeneration may not be economically well-suited to an office building that is lighted and air-conditioned only during a nine-hour business day.

Specific need for heating or cooling is also a factor. An application that involves no cooling load is a natural for a pack-

Utility Reactions

Utilities have responded to the challenge of packaged cogeneration in a variety of ways. Those with ample generating capacity and a heavy commercial load have fought the incursion vigorously by adjusting rates and promoting electric alternatives. Some utilities with low reserve margins, however, have actively encouraged cogeneration by their customers and have even set up nonregulated subsidiaries to invest in packaged cogeneration systems for the commercial sector.

Initiating time-of-day rates in order to ensure fair treatment of all customers is a common utility response to increased cogeneration. If a substantial number of customers were to install cogenerators and reduce their own baseload demand, other customers would eventually have to pay higher rates. To prevent this, a utility can offer sharply reduced baseload rates for off-peak hours, which makes cogeneration less attractive.

Many utilities are also adopting more active marketing strategies to promote the use of advanced electric equipment, according to Clark Gellings, senior program manager for demand-side planning. "They're using more sophisticated forecasting and marketing techniques, which include helping customers obtain financing for equipment purchases," he says. "EPRI is participating in this effort by providing guidebooks and analytical tools that can help utilities do comprehensive market planning."

Northeast Utilities, on the other hand, is promoting cogeneration projects in its service territory as part of an overall effort to avoid building any new generating capacity until after the turn of the century, despite higher-than-expected demand growth. Northeast's marketing plan involves providing a free preliminary assessment of cogeneration potential and, if the outcome is favorable, introducing the customer to a third-party developer. Such cogeneration capacity, developed under contract and with utility participation, is then subtracted from load forecasts. Northeast expects that about 70 percent of this cogeneration will be derived from small, packaged systems.

Some utilities are offering service contracts to commercial customers with packaged cogeneration systems. Such contracts help ensure that cogenerators comply with utility safety standards and do not produce poor-quality power, which could cause voltage irregularities on utility lines.

By far the most common service that utilities are offering potential buyers of packaged cogenerators is an objective, site-specific evaluation of their energy needs. This analysis often reveals inexpensive energy management and utilization options that can substantially reduce electric power costs. The assessment also helps inform the customer of advanced electric alternatives to cogeneration that cost far less and have shorter payback periods. □

aged cogeneration system, as the waste heat from the unit can be used more or less directly for water or space heating. If air conditioning is required, on the other hand, the cogeneration package must include an absorption chiller, which increases the cost of the system by about 25 to 50 percent.

"When you're dealing with only a sustained heating load, such as a large swimming pool or greenhouse that is heated around the clock, cogen can be difficult to beat," says Fickett, "but that kind of application doesn't come up very often. When you have to provide air conditioning too, electric technologies provide strong competition."

Serving cooling loads is where advanced electric equipment really shines, offering high efficiencies at relatively low cost. For example, a 70-kilowatt cogenerator for a fast-food restaurant would cost about $117,000, with an absorption chiller sized to handle the air conditioning; the same air conditioning load could be provided by an electric reciprocating chiller costing only about $4500. Similar savings are available for other cooling applications and technologies; sales of electric cool storage systems are on the rise, and advanced supermarket refrigeration systems are proving to be 20 to 35 percent more efficient than conventional units.

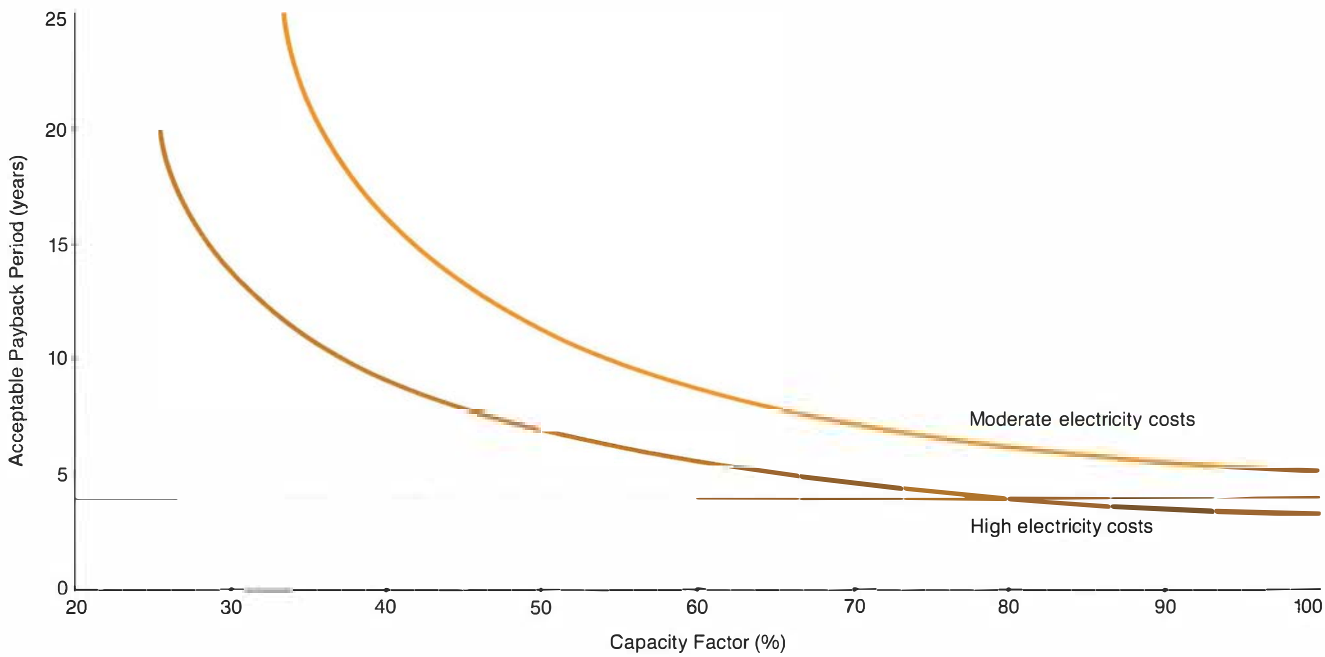
Getting down to cases

When it comes down to making a purchasing decision, generalities and rules of thumb take you only so far. Therefore EPRI has conducted a number of surveys and case studies to provide utilities with the data and analytical tools they need to help their customers evaluate the potential for packaged cogeneration systems—to study how such systems are actually performing and where advanced electric alternatives would be more cost-effective.

A survey of more than 50 facilities powered by small cogeneration systems revealed some disappointments, particu-

Capacity Factor Is Key

The capacity factor of a packaged cogeneration system—how many hours a day it is operated—significantly affects its economics. In this example of an office building with a computer center, the cogen system would have to be utilized about 19 hours a day (80% capacity factor) to realize a four-year simple payback, even when cost assumptions are optimistic and electricity rates are high. When electricity rates are moderate, the system won't be able to pay for itself in that period even if it is run 100% of the time.



larly in the areas of maintenance and reliability. Owners found that even small cogeneration systems are sufficiently complex to require considerable maintenance by experienced personnel (estimated by EPRI studies to cost between 1.2 and 2 cents per kilowatthour). Many of the reported outages apparently resulted from design faults in the packaged units. Some engines, for example, had not been sufficiently redesigned for conversion from diesel fuel to natural gas.

Such shakeout problems are not unusual in relatively new industries that have not yet codified design and operation standards, but manufacturers will have to feature improved availability in their mature units to establish a favorable reputation for the industry. The survey found that facilities that purchased maintenance contracts from the manufacturers experienced far fewer outages than those without contracts.

Longer-than-expected payback periods were also noted in the survey results. "Customers were particularly interested in this aspect of packaged cogeneration units," says Project Manager Hans Gransell, an employee on loan to EPRI from Studsvik Energy of Sweden. "They had been led to expect payback in two to three years, but our survey found that five to six years is more likely."

The question of payback was dealt with more rigorously in a series of case studies EPRI designed in 1985 to compare the relative merits of packaged cogeneration systems and high-efficiency electric technologies. Potential cost savings and payback periods were first calculated for each of five typical commercial applications; cogeneration and conventional electric systems were compared under three electricity-to-gas rate scenarios. High-efficiency electric alternatives were then identified and compared with the baseline electric equipment. Finally, the savings and payback periods for cogenerators were computed by using advanced electric alternatives as a basis for comparison.

"These case studies showed that packaged cogenerators will not be cost-effective where electricity rates are low," concludes Subprogram Manager Mort Blatt. "Cogeneration is generally a viable alternative where electricity rates are moderate or high, but installing more-efficient electric alternatives usually offers faster payback periods and lower investment costs. Unfortunately, many packaged systems have been marketed on the basis of optimistic capital and maintenance costs and by comparing them to conventional equipment rather than to the best available electric technologies. Utilities need to provide customers with adequate information and support for objectively evaluating all alternatives."

Analyzing Cogeneration Proposals

Packaged cogeneration systems have been marketed aggressively by their manufacturers. The prospective owner should be aware of several pitfalls when analyzing the pros and cons of a cogeneration proposal.

Understated first costs. In addition to the capital cost of the basic cogen unit, a proposal should account for such "incidentals" as the costs of site preparation, interconnection to the building's hot water lines, electric interconnections, FERC permits, insurance, and gas service contracts.

Understated maintenance costs. Maintenance costs typically run between 1.2¢ and 2¢/kWh, amounting to as much as $17,000 a year for a 220-kW unit operating 5000 hours. Estimates much lower than this should be scrutinized carefully, and it should be made clear that upkeep of auxiliary items such as heat exchangers, water pumps, and mufflers is included. In addition, engines generally require rebuilding at 15,000-hour intervals for 1800-rpm units and at 40,000 hours for 1200-rpm engines, at a cost that can run $140/kW.

Balance of electric and thermal loads. If the bulk of the engine's waste heat cannot be used productively while the unit is generating electricity, the system's advantages disappear entirely. Since the thermal load of most commercial buildings fluctuates significantly with the time of day and season, cogeneration evaluations should be based on actual operating load profiles, not average values.

Capacity factor. The lower a system's capacity factor (the percentage of time it is actually operating), the poorer its economics. If a unit is utilized only during a 10- or 12-hour business day, cogeneration is unlikely to be a cost-effective option.

Effect of outages. Like any other mechanical equipment, cogeneration systems are subject to unplanned shutdowns, and owners must arrange for their own repairs unless they have purchased service contracts. Surveys have shown that the reliability of packaged cogen units has been somewhat lower than owners expected. During unscheduled downtime, power must be purchased from the local utility, potentially resulting in high demand charges.

The five cases studied were an athletic facility, a fast-food restaurant, a supermarket, an office building, and a hospital. And, Blatt points out, the study was performed (in 1985, under old tax laws) using optimistic assumptions for cogenerator performance, since actual operating data were not yet available. A full report on the studies, including the detailed economic analyses, will be available later this year.

The case study that proved most promising for cogeneration was the athletic facility, situated in a region with moderate to high electricity rates. An important factor in this favorable evaluation was that a large part of the facility's energy needs involved heating a swimming pool, which could be accomplished directly by the cogenerating unit's waste heat.

Of the five cases studied, clearly the worst for cogeneration was the fast-food restaurant. The main drawback for this application was relatively low utilization because of the restaurant's limited hours of operation. A high-efficiency roof-top air conditioner would be a more attractive alternative under all rate scenarios.

Supermarket refrigeration units operate around the clock and thus would seem to offer an attractive market for manufacturers of cogeneration systems, but advanced electric equipment provides stiff competition. The case study evaluated a prototype cogeneration system now undergoing field tests in Los Angeles, a system that uses a gas engine to drive the refrigeration compressors and an absorption chiller to provide refrigerant subcooling. The study showed that such a unit could pay for itself in about three and a half years where electricity rates are high. A state-of-the-art electric refrigeration system, however, would have a payback period of only about seven months under the same circumstances.

Hospitals provide several potential advantages to cogenerators: round-the-clock operation, substantial baseload requirements for both electricity and thermal energy, and usually the presence of maintenance personnel who are familiar with operating engines for emergency backup power. On the other hand, the study showed, high-efficiency electric chillers are available that offer about the same payback period at a lower capital cost and with much simpler installation.

Cogeneration is not usually attractive for office buildings because of the low utilization resulting from limited occupancy hours. A possible exception, however, is an office building with a computer center that operates 24 hours a day and provides a substantial cooling load to a cogenerator via absorption cooling. When analyzed as a case study, such a building was found to offer a three- to four-year payback period for a cogeneration system. The electric alternative considered was a high-efficiency centrifugal electric chiller, which would provide a 1.5- to 1.8-year payback period.

Spreading the word

To help utilities use the information gathered from research on packaged cogeneration systems, EPRI is publishing the *Handbook of Electric Alternatives to Cogeneration in Commercial Buildings*. Prepared by Resource Dynamics Corporation of Vienna, Virginia, the handbook presents a step-by-step approach a utility representative can use in evaluating cogeneration systems and electric alternatives for individual customers.

"Over the short term, the handbook will enable utilities to respond to customer interest in cogeneration by helping them analyze the real costs and risks," says Richard Friedman, executive vice president of Resource Dynamics. "Over the long term, it will help utilities become more proactive in helping customers find the most energy-efficient options—reducing loads with electric chillers, better refrigeration equipment, and so forth."

Another part of the technology transfer effort is a seminar, to be held October 19–21 in San Diego, that will provide the latest information on packaged cogeneration systems, high-efficiency electric equipment, and rate and service options.

The methodologies developed during EPRI studies of commercial-sector cogeneration are also being incorporated into two software packages. One, a screening tool intended for use by nontechnical utility personnel, will be ready in early 1989. The other, a more detailed engineering analysis of packaged cogenerators, is expected to be available for testing near the end of next year. Both programs are being designed to run on microcomputers.

"This is still an embryonic area," says Paul Stapleton, an employee on loan to EPRI from San Diego Gas & Electric who is working on the computer programs. "But we're taking the lead in developing tools that will enable utilities to help customers make informed decisions and strengthen their own marketing strategies." ■

This article was written by John Douglas, science writer. Technical background information was provided by Arnold Fickett, Mort Blatt, and Hans Gransell, Energy Management and Utilization Division.

TECH TRANSFER NEWS

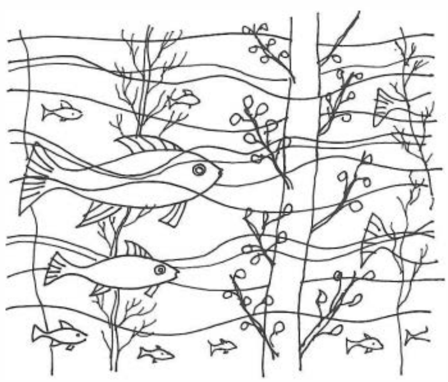
RAMAS Helps Protect the Aquatic Environment

EPRI's Environment Division has developed several computerized tools to help utilities understand the environmental impacts of electricity generation, work with regulators to identify problems, and implement cost-effective solutions. One such tool coming into increased and varied use by utilities around the country is the Risk Analysis and Management Alternatives System (RAMAS), a personal computer software package that can analyze the population response of fish and other forms of aquatic life to man-made impacts. Utilities are now using the program in many different ways, demonstrating its versatility and applicability to a variety of environmental studies.

Rather than analyzing the response of individual organisms to pollutants and other man-made impacts, RAMAS looks at the probable response of an entire population of a given species. Utilities can thus predict the influence of their operations on the abundance of the species found in the local environment, calculating the probability of the species either being unchanged in its numbers, increasing, declining, or disappearing from the local ecosystem as a result of different utility operating practices and management decisions.

To use RAMAS, utilities enter biological information on the species being studied, including information specific to different age classes within the species (e.g., eggs, larvae, juveniles, and adults). Since man-made impacts affect different age classes differently, the age-specific information is needed to calculate the probable effects on the entire population. The model can also allow for reproductive effects that are dependent on population density in some species.

RAMAS is sufficiently flexible to be applicable to different aquatic species. At Southern California Edison (SCE), for example, scientists are using a version of RAMAS to study the impact of diffuser systems at the San Onofre nuclear generating station on the ocean kelp beds near



the plant. Kelp is an important part of the local ecosystem, and it also creates a gold-colored lane on the ocean surface along the shoreline that adds to the aesthetics of the California coast. "Since light affects kelp growth, we wanted to explore the possibility that turbidity in the water caused by the station's diffuser system might keep sufficient light from getting to young kelp near the ocean bottom," explains John Palmer, a consulting scientist at SCE. "Using RAMAS, we've made some preliminary findings that show changes in turbidity to have only localized effects on the kelp population."

In an application at Carolina Power and Light (CP&L), scientists used RAMAS in 1987 to evaluate the long-term effects of selenium from a fly ash pond discharge on the population of bluegill sunfish in a power plant reservoir. Having taken steps to eliminate the selenium discharge, the utility wanted to calculate the time needed for the bluegill population to recover. "RAMAS helped us establish that the chances of bluegills disappearing from the reservoir were extremely low, and that the population was likely to recover in two or three bluegill generation cycles," says Bobby Ward, a CP&L scientist.

Another RAMAS application, cosponsored by New York Power Authority and Consolidated Edison, focused on the striped bass population in the lower Hudson River and its response to entrainment and impingement of juvenile fish on power plant intake screens. "Results showed that the effect of fishing mortality on the population can be greater than that due to entrainment and impingement on intake screens," says Dennis Dunning, a scientist at NYPA. "We should be prepared to evaluate the population's response to various combinations of power plant and fishing mortalities, particularly if the commercial harvest of striped bass is allowed to resume and sport-fishing regulations become more liberal. RAMAS allows us to adopt a proactive, rather than reactive, approach to these environmental and regulatory issues."

Overall, RAMAS has now been ordered by more than two dozen utilities, which reflect a wide variety of generating technologies, geographical regions, and environmental concerns. In addition, the U.S. EPA is currently evaluating the software for use in its ecological analyses. ■ *EPRI Contact: Abe Silvers (415) 855-2615*

Robot Inspects Steam Generator at Indian Point-2

The buildup of sludge on the secondary side of steam generator tubes in nuclear power plants can cause corrosion problems requiring costly repairs, extended outages, and—in some cases—replacement of the entire steam generator. Utilities generally use water lancing or chemical cleaning to remove the sludge. Access to tubes deep inside the steam generator tube bundle has been limited, however, and that has made it difficult for utilities to perform inspections and to reach and remove the sludge with jets of water. Chemical cleaning, on the other hand, may not be effective in removing certain kinds of sludge and may not be compatible with operations at some utilities.

Recognizing the need for an improved system for steam generator inspection and cleaning, EPRI, Consolidated Edison Company of New York, and the Empire State Electric Energy Research Corporation (ESEERCO) developed CECIL, the Consolidated Edison Combined Inspection and Lancing system. This unique teleoperated robot was put through its first field trials in October 1987 at Con Edison's Indian Point Unit 2, where it showed its effectiveness in making visual inspections and its feasibility as a water-lancing tool for sludge removal.

Cylindrical in shape and about the size of a large thermos bottle, CECIL uses a specially designed flexible lance that is equipped with both a video camera and metal conduits to deliver high-pressure jets of water. For the field trials at Indian Point-2, the robot was inserted through the 6-inch-diameter inspection port and onto the blowdown pipe that runs horizontally through the secondary side of the steam generator. Personnel at a remote station on the containment operating floor propelled CECIL along the blowdown pipe, watching on a video screen as they positioned its flexible lance in front of the passages between tubes and extended the lance into the tube bundle. CECIL moved along the pipe in a crablike fashion, its feet extending and then retracting as they moved the robot forward.

Video inspection performed with CECIL during the demonstration provided the operators with an unprecedented, clear view of sludge buildup deep inside the tube bundle. "The fiber-optic probes previously used for visual inspection are not capable of delivering images of the clarity provided by CECIL's video camera," explained Steve Trovato, a senior research engineer at Con Edison. "The system represents a real breakthrough in our inspection capabilities and could help us identify the extent of the sludge pile and determine what will be needed to remove it."

CECIL's water-lancing capabilities were also tested, and in this case the developmental robot proved less effective. Although CECIL's water jet eroded some sludge off a pile on the cold leg of the tube bundle, it was not able to blast away all of the hard deposit. "We expect that higher water pressures and further refinement of CECIL's jet orifices will enable it to remove sludge more rapidly," comments Trovato. "Further development work is required before CECIL's usefulness as a sludge-lancing tool can be established."

Con Edison, ESEERCO, and Public Service Electric and Gas are currently overseeing development work on the robot, along with Foster-Miller, the contractor that built the prototype used in the field trials. In addition to making improvements based on the experience at Indian Point-2, developers are exploring new capabilities such as foreign object search and retrieval, detection of leaking tubes, photography of tube support plate flow slots, and adaptation of the robot to steam generator designs other than the Westinghouse Model 44 steam generators in service at Indian Point-2. Con Edison is considering another field test on an improved version of CECIL during a scheduled outage in the spring of 1989. ■ *EPRI Contact: C. Lamar Williams (415) 855-2789; Utility Contact: Steve Trovato (212) 460-2090*

Using Residual Fuel Oil for Generation

In the last decade, unstable conditions in world oil markets have caused deterioration and increased variation in the quality of the residual fuel oils fired in some utility power plants. This decline in quality, combined with more-stringent NO_x and particulate emissions standards, has caused utilities to experience severe operating problems. A new resource, *Residual Fuel Oil User's Guidebook*, Volumes 1–4 (AP-5826), will help utilities address these problems.

The guidebook confirms that residual fuel oil can be an economically and environmentally viable fuel for utility boilers, gas turbines, and diesel engines; however, proper use of this fuel requires attention to specification, purchase, testing, handling, treatment, storage, operations, and maintenance. The guidebook advises utilities on all these topics, with Volume 1 providing an overview and an extensive bibliography. Volume 2 covers utility boilers; Volume 3 applies to stationary gas turbines; and Volume 4 focuses on diesel engines used for electric power generation. ■ *EPRI Contact: Henry Schreiber (415) 855-2505*

Energy Utilization

Cost Comparisons of Commercial Cooling Alternatives

by Ronald Wendland, Energy Management and Utilization Division

Utility marketing, load management, and demand-side planning programs often focus on air conditioning for commercial buildings, which is a major source of summer peak demand for many utilities. Recently, the task of developing this market and using it to shape load has been complicated by the introduction of new electric and gas-fired cooling technologies. Of the newer electricity-based alternatives, thermal energy storage (cool storage) provides utilities with a means to reduce peak loads, improve load factors, increase off-peak sales, and lower customer electricity bills. At the same time, gas-driven cogeneration, gas air conditioning, and other emerging technologies are competing with both conventional electric air conditioning and cool storage. For utilities, this changing picture creates both opportunities and competitive pressures, as well as the need for new computer-based tools for making economic and market assessments of the various cooling alternatives.

Responding to these requirements, EPRI developed two new microcomputer-based screening tools, COOLAID and COOLGEN, to help utilities analyze and promote commercial cooling systems.

COOLAID is a PC-based software package that allows utility analysts to evaluate the cost-saving potential of individual cool storage installations as compared with conventional electric cooling systems. The COOLAID software has been available through the Electric Power Software Center since 1987, and more than 30 utilities are using it in direct marketing and planning programs.

COOLGEN, now in prerelease, is a similarly structured program for evaluating the economics of gas-fired cogeneration and absorption technologies for commercial cooling. Utilities can use the COOLAID and COOLGEN programs individually or in combination to promote cool storage and to compete more effectively with cogeneration and other gas-fired cooling alternatives.

COOLAID

Cool storage systems use standard HVAC equipment and ice or water storage tanks to shift the period of chiller operation in commercial buildings from peak to off-peak periods. Utilities are increasingly promoting these systems as a major component of their demand-side planning programs. By shifting electricity use to off-peak hours, cool storage benefits both the utilities and their customers. Utilities can reduce their peak load, increase off-peak sales, and improve their competitive position with respect to gas-fired alternatives. Customers, taking advantage of specially designed utility rates and incentives, enjoy lower electricity bills.

Utility involvement and technology improvements are stimulating the market for cool storage, which continues to expand beyond the more than 1000 commercial cool storage systems installed in the United States by 1987.

Since the early 1980s EPRI's Energy Management and Utilization Division has developed a variety of materials and products aimed at helping utilities understand and promote cool storage, including a cool storage primer (EM-3371), a design guide (EM-3981), and a marketing guidebook (EM-5841). The primer provides examples of a method for developing estimates of

ABSTRACT *Cooling systems for commercial buildings are changing as new electric and gas-driven technologies become available. Cool storage systems, which shift high energy use periods from peak hours to off-peak hours, provide better load factors for utilities and lower energy costs for customers. Two new EPRI computer programs are helping utilities make the economic assessments of cooling alternatives they need in order to promote cool storage systems and to compete more successfully with gas-driven alternatives.*

the operating and capital cost effects of cool storage systems. In 1985 EPRI contracted with Regional Economic Research (RER), of San Diego, California, to automate this method through the development of COOLAID.

COOLAID is specifically designed for analysis of individual cool storage systems in commercial buildings. It compares the cost of each installation with that of conventional alternatives and evaluates the customer's potential cost savings. In addition, utility analysts can use the program to calculate the sensitivity of the customer's cost savings and payback period to variations in electricity rate structures, utility incentive programs, technology features, and equipment costs.

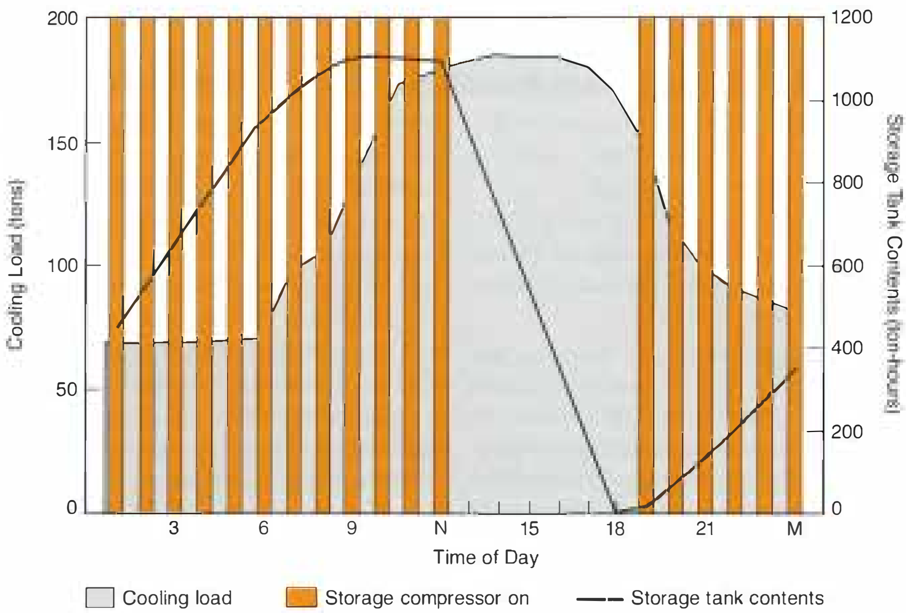
Overall, the program can serve four main purposes: personnel training, market analysis, rate and incentive design, and customer information. As a training tool, COOLAID can be used to familiarize personnel with cool storage technologies and to teach them how to identify factors that make these technologies an attractive option. In market analysis, the program allows the user to identify target markets for cool storage installations and to analyze the technology's attractiveness to those market segments.

As a tool for rate design and for incentive design, the program evaluates the effects of alternative rate designs and incentives on customer energy costs and return on investment. Also, the program can aid direct-marketing efforts by providing information pertinent to individual customers, including comparisons of electricity bills, equipment costs, and payback periods for both cool storage and conventional systems.

To operate the program, users supply the following input information, available from load research or heat load model results, manufacturers' literature, or records from existing cool storage installations.

□ Building energy-use data, including air conditioning and other loads. COOLAID furnishes building load profile prototypes for nine building types in seven climate zones that can be adjusted to suit individual customer installations.

Figure 1 Cool storage system sizing. Given the design-day cooling load and an operating strategy, the COOLAID software will determine the appropriate size for a cool storage system. In this example, the system provides for full storage; that is, during the utility's peak period, the cooling load is met completely from storage and the compressor does not run.



□ Time-of-use rate structures for up to four seasons per year. COOLAID allows users to specify separate rate structures for conventional and storage cases.

□ Technology data, including system efficiencies and equipment costs for both conventional and storage systems, and incentives offered to encourage storage installations. The COOLAID user's guide describes various types of cool storage systems and provides reference data on equipment efficiencies and installation costs.

□ Operating strategies for the air conditioning peak day of each month. Strategies can include unrestricted compressor use, fractional lockout, or full lockout for each day.

Program output includes storage system size (calculated instantly on the basis of design-day operating loads and a specified operating strategy), comparative operating and equipment costs for both conventional and storage system alternatives, return on investment, and payback period. COOLAID provides numerous summary graphs and tables for on-line review (Figure 1). A variety of printed reports generated by the program present energy use and electricity bills for each month and time-of-use period. In addition, an economic summary illustrates the effect of energy cost savings and the effect of equipment costs on the customer's payback period.

COOLAID is easy to use, providing a menu-driven series of screen displays to prompt the user, on-line help screens, interactive tables and graphs to illustrate user input, and file-handling capabilities that allow the user to develop a library of case studies for future use. The program runs on the IBM PC or IBM-compatible family of computers and requires an available memory of 512K.

Through RER, EPRI provides ongoing support services for the software. RER offers telephone consultation services and distributes prototype load shapes and updates as they become available. A descriptive brochure is also available through EPRI's Energy Management and Utilization Division (EU-2010).

The COOLAID program is being revised (COOLAID 2.0) to expand the treatment of storage systems, provide greater rate structure flexibility, include more details of equipment performance, and make program execution faster and easier. The expanded treatment of storage systems will provide the capability of evaluating mixed storage systems in which different types of compressors are used; the more-flexible rate structure will allow the program to handle multiple meters, load-factor extender blocks, and seasonal ratchets.

A demonstration version of COOLAID 2.0 is available and can be obtained through RER. General release is planned for the last quarter of 1988.

COOLGEN

Gas-driven cogeneration, gas air conditioning, and other packaged technology combinations are rapidly emerging as competitive alternatives to the use of electricity for cooling commercial buildings. In response, EPRI and the Edison Electric Institute (EEI) published a technical brochure providing comparisons of commercial cogeneration with high-efficiency electric alternatives, including cool storage (EU-3009). Drawing on results of a 1985 EPRI study, the brochure reported that in commercial building applications, cool storage and other high-efficiency electric technologies can typically supply building energy needs more economically—and with less technical and financial risk—than can cogeneration and other gas-fired alternatives.

To automate and standardize these kinds of comparisons, in 1987 EPRI contracted with RER to develop COOLGEN, a PC-based program that performs economic analyses of cogeneration and other gas-driven commercial cooling alternatives. COOLGEN is being designed for use in conjunction with COOLAID, which it closely parallels in program structure and usefulness to utilities. Much like COOLAID, COOLGEN calculates the customer's potential equipment costs, energy costs, and payback period, as well as the sensitivity of these factors to utility rate structures (Figure 2).

Input requirements for COOLGEN reflect the uniquely complex interaction of factors that determines the cost of adopting cogeneration for commercial buildings. The user provides a compact set of information required to perform simplified sizing calculations and to determine equipment and operating costs. These data describe the following.

- A building's energy use for cooling, displaceable heating, and site electric loads (default energy-use data sets for nine building types in seven climate zones are available with the program)
- Utility electric rate structure
- Cogeneration rate data, seasonal buyback rates, and contract demand and standby charges
- Fuel rate structure
- Technology parameters related to cooling, heating, and cogeneration equipment efficiencies and costs
- Operating strategies

A user's guide will describe the technology parameters and provide estimated cost ranges for a variety of system types.

COOLGEN combines this information and provides estimates of system costs, monthly energy bills, and operating costs for both a conventional system and a cogeneration or absorption alternative. Intermediate results can be viewed both graphically and in tabular form throughout the program, allowing the user to preview and select from a variety of output tables. The program features a menu-driven format similar to that of COOLAID; it runs on a PC or IBM-compatible computer.

The analysis framework, program specifications, and user's guide for COOLGEN are now complete, and the software is in prerelease to San Diego Gas & Electric and to Florida Power & Light, who are participating in beta testing with the contractor. Shortly, several other utilities are expected to participate in testing. Production release of the

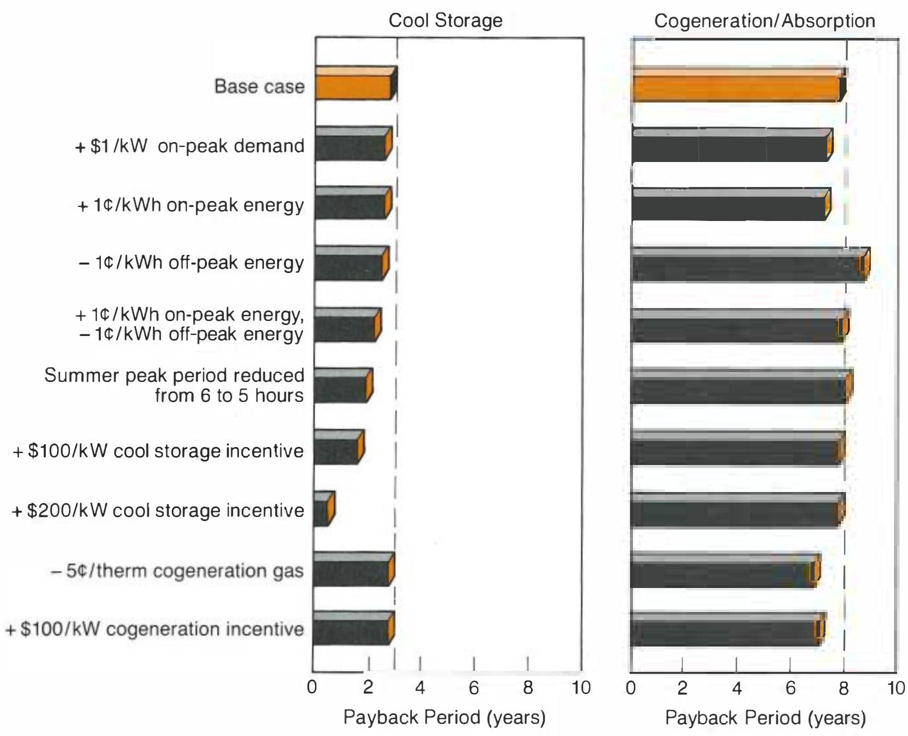


Figure 2 **COOLAID and COOLGEN were used to calculate the sensitivity of the payback period to utility rates for electricity-based cool storage and gas-driven cogeneration/absorption, respectively. The analysis assumed the application of these cooling technologies to office buildings in a warm climate and explored several variations in a base-case rate scenario.**

software is scheduled for early 1989.

RER is also using the software to perform sensitivity analyses on factors affecting the comparative economics of gas and electric options. The results indicate that the economics of cogeneration are strongly influenced by rate structure. EPRI plans to use results from this work to analyze the aggregate effects of cogeneration and of other gas-fired systems on commercial cooling markets, and to select candidate electric technologies for future development.

Air Quality Control

Spray Drying for High-Sulfur Coal

by Richard Rhudy, Coal Combustion Systems Division

ABSTRACT *Recent pilot plant tests indicate that spray drying, now used to control SO_2 emissions from low-sulfur coal, can also be effective for high-sulfur coal. Spray drying coupled with baghouse particulate removal is the most effective configuration tested to date, removing over 90% of SO_2 while easily meeting New Source Performance Standards for particulate emissions.*

Acid rain legislation enacted by some states and pending at the federal level has increased interest in alternative methods of removing sulfur from flue gas. The long-term reliability and maintainability of spray drying, which is used to control SO_2 emissions in low-sulfur coal, have led to interest in expanding the use of this technology to high-sulfur coal.

Preliminary EPRI pilot plant results show that spray dryer–baghouse combinations are over 90% effective at removing SO_2. Spray dryer–baghouse combinations also control particulate emissions very well, easily meeting the 0.03 lb/10^6 Btu federal particulate standard for new sources. In testing completed to date, spray dryer–electrostatic precipitator (ESP) combinations have not achieved as high a level of emission control; they remove around 80% of the SO_2 and generally emit less than 0.11 lb/10^6 Btu of particulates.

Two EPRI-sponsored studies, begun in 1987, are evaluating spray drying for high-sulfur coal. In cooperation with the Tennessee Valley Authority (TVA) and Ontario Hydro, EPRI is sponsoring a three-year test of a spray dryer followed by an ESP, concentrating on the applicability of this technique for plant retrofit. This test is being conducted at TVA's Shawnee station, using a 10-MW facility. Measurements on 4% sulfur coal are complete. Further work with 2.5% sulfur coal is currently in progress.

At EPRI's High-Sulfur Test Center (HSTC), located at the Somerset station of New York State Electric & Gas, a five-year program tests spray drying, primarily in combination with a baghouse, at a 4-MW facility. This program is aimed at understanding the use of spray dryers for both new and retrofit applications.

In the HSTC tests, flue gas from a high-sulfur coal (2.5–3% sulfur) is spiked with SO_2 to a controlled SO_2 content at the inlet (tests with 2500 ppm SO_2 are reported here). At this facility, there is also a limited amount of testing of a spray dryer–ESP combination. Because many high-sulfur coal power plants already use ESPs for particulate control, spray drying combined with ESP could be a low-cost SO_2 control option for stations that must retrofit.

Spray dryer–baghouse tests

Prior EPRI evaluations of the spray dryer–baghouse combination took place at EPRI's Arapahoe Test Facility and at the Riverside station of Northern States Power. Arapahoe's testing was conducted on a 2.5-MW spray dryer–baghouse treating low-sulfur coal; the flue gas was spiked with SO_2 to simulate high-sulfur operation. The spray dryer at the Riverside station treated flue gas from two boilers with a generating capacity of 100 MW. For the test, the boilers were fired with 3.4% sulfur Illinois bituminous coal.

However, simulation of high-sulfur operation by spiking low-sulfur coal flue gas with SO_2 (as at Arapahoe) is not as realistic an emission control test as using actual high-sulfur coal flue gas, and the experiments at Riverside using high-sulfur coal were very short term (two weeks). Therefore, a comprehensive program of tests with high-sulfur coal was begun at HSTC in 1987 to provide a more definitive technical evaluation of the

Table 1
COMPARISON OF ARAPAHOE, RIVERSIDE, AND HSTC RESULTS

	Arapahoe	HSTC	Riverside	HSTC
SO_2 removal (%)				
Overall	94	95	88	90
Spray dryer	71	80	73	78
Fabric filter	23	15	16	13
Reagent ratio	1.36	1.42	1.33	1.41

technology. As shown in Table 1, initial results of the HSTC tests compare well with the limited testing done earlier at Arapahoe and Riverside.

As Figure 1 illustrates, the ability of the baghouse to remove SO_2 makes the spray dryer–baghouse combination very effective. In these combinations, 60–75% of the sulfur is removed in the spray dryer. More sulfur is then removed as the flue gas passes through the bags of the fabric filter, where unreacted sulfur oxides from the scrubber react with the unreacted lime in the collected solids. Up to 20% of the total sulfur is removed in the baghouse, even though lime utilization in the baghouse is not very effective: only 20–25% of the lime in the baghouse reacts with sulfur, whereas 50–60% of the lime in the spray dryer reacts.

Particulate collection in a baghouse is very efficient, even when there is a spray dryer upstream. In the HSTC tests, the installation of an upstream spray dryer caused five times as much particulate mass to enter the baghouse, compared with a baghouse that just collected fly ash from untreated flue gas. However, the baghouse particulate emissions were constant, with or without a spray dryer. Outlet particulate levels were an order of magnitude below those required by the New Source Performance Standards (0.03 $lb/10^6$ Btu), and removal ratios were above 99.98%.

Spray dryer–ESP tests

Figure 2 shows results from TVA's Shawnee facility. A spray dryer–ESP combination was tested by using a 4% sulfur coal flue gas. (In both baghouse and ESP tests, conditions within the spray dryers were roughly comparable in terms of temperature and approach to saturation.) However, although SO_2 removal in a baghouse unit can be as high as 20%, SO_2 removal in an ESP unit remains near 10%. Therefore, in spray dryer–ESP combinations, total sulfur removal over 80% is difficult to achieve and requires very high reagent ratios (1.7).

Removal rates are better when a high-chloride coal is used. The coal used for the tests in Figure 2 contained 0.05% chloride, as did most of the coal used for the work at Shawnee. When coal with a 0.20% chloride content was fired at Shawnee, removal rates topped 80% at a 1.1 reagent ratio and were above 92% with a 1.7 reagent ratio. Because chloride in the coal becomes calcium chloride ($CaCl_2$) in the spray dryer, this result confirms previous EPRI-sponsored work at Arapahoe showing that $CaCl_2$ additions increase SO_2 removal efficiencies in spray dryers.

In the testing completed to date for the spray dryer–ESP combination, particulate emissions to the atmosphere were higher than those from spray dryer–baghouse combinations or stand-alone ESP units. In general, measured ESP particulate removal efficiencies were not changed by the presence of the spray dryer. However, since more particulate enters the ESP when it is downstream of a spray dryer, the same removal ratio results in more particulate exiting to the atmosphere. Inlet and outlet mass loadings of the ESP increased by a factor of 10 at Shawnee. The particulate emissions generally stayed below the emission standard of 0.11 $lb/10^6$ Btu set by the state of Kentucky. However, spray dryer–ESP particulate emissions were higher than the 0.03 $lb/10^6$ Btu federal particulate standard for new sources, which was achieved in spray dryer–baghouse tests.

As described above, tests to date have shown that reaction solids produced by spray dryers have no noticeable effect on ESP particulate removal efficiencies or solids handling. However, these results were disappointing. The ESP operating conditions during the tests should have resulted in increased ESP particulate removal. The data indicate that conditions may not have been ideal—for example, particulates may have been reentrained. This reentrainment may be the factor that determined the actual measured ESP efficiency. In current tests, researchers are attempting to determine the conditions under which this entrainment may take place and the appropriate operating guidelines to prevent it.

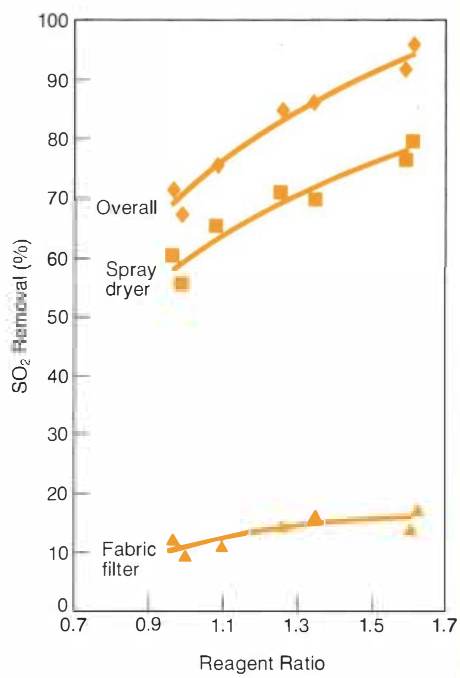
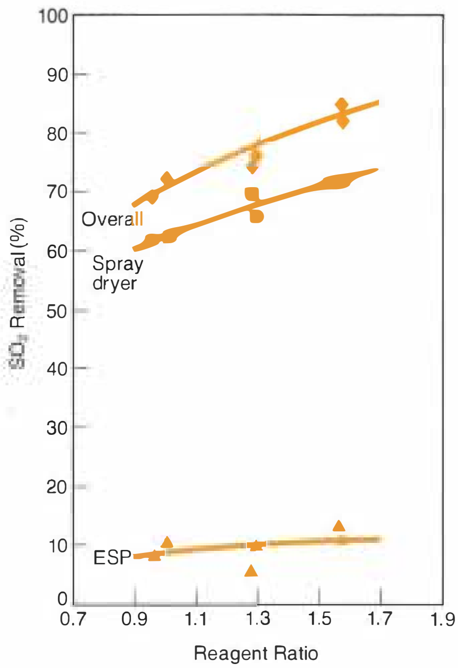


Figure 1 SO_2 **removal rates of 90% were achieved in a spray dryer–baghouse test at HSTC using high-sulfur coal; 10–20% of the** SO_2 **was absorbed by unreacted lime that reached the fabric filter. The tests used Mississippi lime and were conducted at these conditions: 2500 ppm** SO_2**, 300°F inlet temperature, and 20°F approach temperature.**

Figure 2 Spray dryer–ESP combinations produced SO_2 removal rates of 80% in tests carried out at TVA's Shawnee facility. Only 10% of the SO_2 was removed in the ESP. The tests were conducted at 2200–2800 ppm SO_2, 320°F inlet temperature, and 18°F approach temperature. The curves are based on 36 tests at various inlet and approach temperatures and reagent ratios, with separate feed slurries and low-chloride coal.



Future issues

Current work is addressing several issues that have to be resolved to ensure long-term effectiveness for the use of spray dryers with high-sulfur coal. One concern is to determine the role that the source of lime plays in dry scrubber removal efficiency. Lime source was not originally a test variable; previous tests at Arapahoe indicated that all high-calcium, highly reactive quicklimes would behave alike.

Early tests at HSTC were conducted with Mississippi lime, the lime used in the Arapahoe and Riverside tests. However, in three subsequent tests, a less-expensive local lime, Bellefonte, was tested to determine if it would be an acceptable substitute. Surprisingly, with Bellefonte lime, equivalent SO_2 removal rates were consistently achieved at lower reagent ratios. At an SO_2 removal rate of 90%, for instance, the reagent ratio with Bellefonte lime was 1.25, compared with 1.5 for Mississippi lime. Tests are planned to determine which characteristic of Bellefonte lime is enhancing the removal rate.

Maintenance issues are also being addressed. Although some tests show that gases from high-chloride coals are more effectively desulfurized in a spray dryer, other tests have shown that on entering the baghouse, hydrochloric acid from such coals can cause bag-clamp corrosion problems. Also, $CaCl_2$ attracts water; when $CaCl_2$ formed from high-chloride coal enters a baghouse, it can cause a more-cohesive solid to form on the filters. This phenomenon may require changes in baghouse cleaning procedures to minimize pressure drop and may cause problems with solids handling.

Similar concerns with solids handling procedures arise when spray dryer–ESP combinations are used with high-chloride coal. Further, spray dryers drop the temperature of the gas stream entering the baghouse or ESP. In some cases, sulfuric acid–water mixtures may condense on the walls of a baghouse, causing corrosion. Methods of corrosion protection must be evaluated.

Current EPRI-sponsored tests are investigating these maintenance issues. Also, tests using coal of various sulfur and chloride contents are proceeding for both baghouse and ESP combinations. All work is taking place in 4–10-MW facilities; therefore results may be used for the confident prediction of the suitability of spray dryer use for full-scale applications.

Advanced Fossil Fuel Power Plants

Cool Water Coal Gasification Program: An Update

by Ed Clark, Advanced Power Systems Division

Cool Water is a nominal 120-MW integrated coal gasification and combined-cycle (IGCC) power plant that uses the Texaco coal gasification process. Cofunded by Southern California Edison, Texaco, Bechtel Power, General Electric, Japan Cool Water Program Partnership (JCWPP), and EPRI, construction of this IGCC facility at Daggett, California, was completed and operation was begun in mid 1984.

The plant continues to operate successfully on its usual feedstock, a low-sulfur Utah coal, and on several test coals. During high-sulfur coal testing, 32,600 tons of Illinois No. 6 coal and 21,300 tons of Pittsburgh No. 8 coal were burned. In the most recent alternative coal test, 23,000 tons of an Australian coal with a high ash fusion temperature were gasified.

Efforts continue to improve the operability and performance of Cool Water, the nation's first IGCC power plant. Plant capacity and on-stream factors for the last six months of 1987 were 85.3% and 87.6%, respectively. For all of 1987 the factors were 70.5% and 79.3%, compared with 56.7% and 65.9% in 1986 and 49.9% and 61.5% in 1985.

Plant improvements

The steady increase in plant reliability was brought about by refining plant operating procedures and by improving plant equipment. Particularly important were changes to the slurry feed system. For the first 21 months of operation, charge pump shutdowns caused most of the gasifier trips. The original design allowed operation of only one pump at a time, with no provision for

ABSTRACT *Testing continues in EPRI's efforts to improve the performance of the Cool Water IGCC power plant. The versatility of the Texaco coal gasification process in adapting to a variety of coals has been further established, and plant reliability has been significantly increased as a result of more-efficient operating procedures and better equipment.*

switching pumps on-line. Modifications completed in April 1986 allow both pumps to operate simultaneously. Because each pump is capable of supplying 100% of the gasifier's slurry throughput capacity, one pump may be taken off-line for maintenance (and later be returned to service) while the other delivers the gasifier feedstock. Since the change was implemented, there have been no charge pump–related outages.

Refinements in slag handling at Cool Water have improved the plant's reliability and will help reduce the capital cost of second-generation IGCC plants while similarly improving their reliability. Dump chutes have been developed that allow the discharge of slag from the lockhopper directly to the slag pit during periods when the slag conveyors are out of service for maintenance. The carbon conversion normally achieved by the Texaco gasifier on the project's Utah coal (>98%) eliminated the need for slag recycle; this will reduce the capital requirements for future plants.

Efficiency has also been improved considerably. In recent tests with Utah coal, the plant's heat rate was 10,950 Btu/kWh, compared with a 1986 performance of 11,550 Btu/kWh (*EPRI Journal*, November 1986, p. 38) and a design heat rate of 11,306 Btu/kWh. The Texaco burner design and plant modifications involving syngas saturation, steam management, and the heat recovery steam generator have made the conversion of coal to electricity more efficient.

Operators of commercial Texaco-based IGCC plants can expect heat rates of about 9000 Btu/kWh by incorporating a combination of current and advanced technology into the plant design, primarily in the combined-cycle area (AP-3486, AP-5931). The greatest improvements would come from using a reheat steam cycle and an advanced gas turbine with a nominal 2300°F (1260°C) firing temperature.

Alternative coal testing

The testing of three alternative coals—Illinois No. 6 (sponsored by EPRI), Pittsburgh No. 8 (sponsored by Empire State Electric Energy Research Corp.), and Lemington, an Australian coal (sponsored by the JCWPP)—has demonstrated the flexibility of Cool Water in handling a variety of feedstocks and its environmental superiority over conventional coal-fired technology when running on high-sulfur coals.

For the gasification of a coal to be commercially feasible, an acceptably high carbon conversion must be obtained at temperatures low enough to be consistent with an acceptable gasifier refractory life. Higher firing temperatures improve coal utilization but reduce refractory life. For all four of the coals run at Cool Water, carbon conversions above 95% were easily obtained at temperatures corresponding to a two-year refractory life. Gasifier performance on each test coal is shown in Table 1.

The lowest viable operating temperature of the Texaco system is just above the temperature at which the slag is too viscous to flow freely; the upper temperature boundary is set by the minimum acceptable refractory life. Within the lower and upper temperature constraints of slag viscosity and liner life, the selection of an optimum operating point for a given coal is made on the basis of economic considerations: carbon conversion, oxygen consumption, and refractory change-out cost and timing. The Lemington coal test demonstrated the plant's ability to use a coal with an ash fusion temperature above 2600°F (1427°C). A fluxing agent (limestone) was mixed with the coal slurry to reduce the slag viscosity in the gasifier. Lowering the fluid point of the slag allowed operation at a lower temperature, at which liner life and oxygen consumption were commercially acceptable.

The run with the Lemington coal (early 1988) also demonstrated the plant's maturity in terms of its ability to handle different feedstocks. The switch from the usual Utah coal to the high-ash-fusion-temperature coal and back was made while the plant was operating. Electricity production was essentially constant through both transition periods. The power station operated at a 92% equivalent availability (EA) during the Lemington coal test, compared with a 36% EA during alternative coal runs with Pittsburgh No. 8 and Illinois No. 6 in early 1986. By applying the experience gained during the first coal tests to plant operating procedures and equipment design, it was possible to continue reliable commercial operation throughout the run with Lemington coal.

Environmental performance

Cool Water has easily met EPA New Source Performance Standards (NSPS) for coal-fired power plants with all the coals tested. SO_2 and NO_x emissions were 10–15% of those allowed under NSPS. Sulfur removal efficiency was 96–98% on both the low- and high-sulfur coals, and 99.5% of the sulfur removed from the synthesis gas was recovered as a salable by-product.

The plant demonstrated exceptional feedstock flexibility in being able to handle coals of different sulfur content, ranging from 3.1% for the Illinois No. 6 coal to 0.35%

for the Southern Utah Fuel Co. (Sufco) coal. An 8-to-1 turndown was achieved with respect to coal sulfur content. Sulfur removal operations were stable, consistently meeting SO_2 emissions criteria on both the high- and low-sulfur coals.

In heat rate calculations for IGCC plants, where the energy required in higher heating value (HHV) to generate 1 kWh of power is determined, coals such as Illinois No. 6 and Pittsburgh No. 8 are penalized because of their higher sulfur content. The sulfur would add to the heating value of the coal, but it is removed (for environmental reasons) before its heat of combustion can be utilized for power generation. At Cool Water, the small drop in heat rate caused by sulfur removal has been compensated by the revenues realized from the sale of the sulfur. Also, the sale of sulfur in an IGCC unit eliminates disposal costs for sulfur-containing solids.

Testing has shown that the slag from all the coals fired at Cool Water is not hazardous. A commercial use for this mineral matter is being sought; applications being considered include secondary coarse roadbed material and lightweight aggregates.

Increased throughput

At the request of the Cool Water Coal Gasification Program, the plant's regulatory agencies increased the maximum permitted coal feed rate from 1008 to 1200 (dry) tons per day on April 29, 1988. During a test, the plant was able to produce 134 MW at an ambient temperature of 60°F (16°C), compared with its design capability of 120 MW. The design firing temperature of the combustion turbine was reached at the 134-MW production level. Since the combustion turbine's output is affected by outside air temperature, the plant's maximum throughput will be a function of ambient conditions, increasing at lower outside air temperatures and decreasing at higher temperatures. The facility continued to meet all air emissions criteria at the high rates. Plans are to continue operating the plant above its 120-MW design capacity in order to maximize production revenues and evaluate equipment performance and equipment operating life-

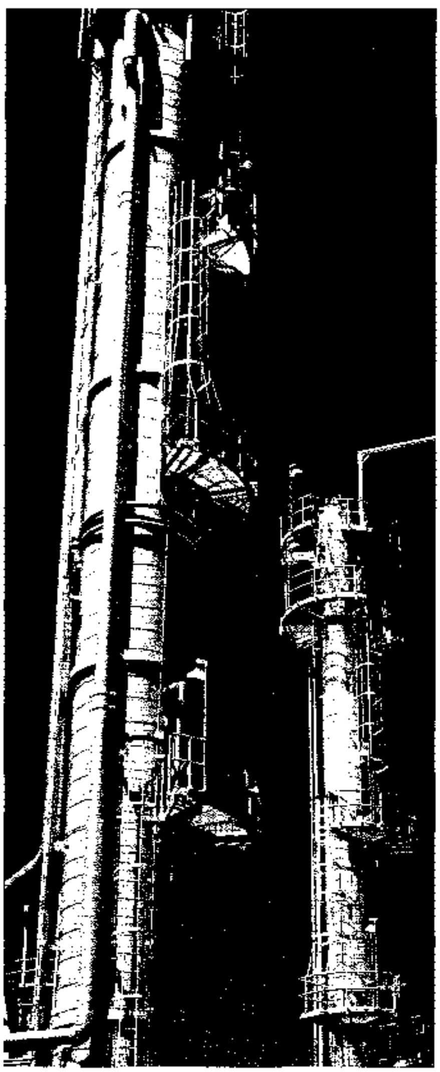


Table 1
GASIFICATION PROCESS PERFORMANCE WITH FOUR COALS

	Sufco	Illinois No. 6	Pittsburgh No. 8	Lemington
Dry coal				
Feed rate (t/d)	1000	1000	934	980
Composition, dry (wt%)				
Carbon	71.9	72.2	77.7	72.4
Hydrogen	4.9	4.9	5.3	4.7
Sulfur	0.4	3.1	2.7	0.5
Nitrogen	1.2	1.3	1.5	1.6
Ash	8.8	11.3	7.4	13.4
Higher heating value (Btu/lb)	12,360	12,970	14,100	12,730
Oxygen				
Flow rate (1000 scfh)	888	910	933	988
Purity (%)	99.5	99.5	99.5	99.5
Clean syngas				
Flow rate (1000 scfh)	2942	2940	3016	2940
Composition (vol%)				
Carbon monoxide	43.0	44.8	44.3	44.2
Hydrogen (H_2)	38.1	38.4	39.4	36.9
Carbon dioxide	18.1	15.5	15.5	18.0
Methane	0.2	0.2	0.2	0.1
Nitrogen (N_2), argon	0.6	1.1	0.7	0.9
Hydrogen sulfide, carbonyl sulfide	0.0	0.0	0.0	0.0
Higher heating value (Btu/scf)	264	271	272	262
Syngas cooler steam production (1000 lb/h)	250	256	235	289
Overall carbon conversion (%)	98.9	97.2	97.8	98.0

time at increased throughput.

Future efforts

A real-time simulator is being developed for the Cool Water plant for use in operator training. This computer system will adapt existing generic IGCC simulation models (developed previously for EPRI) to the specific configuration of the Cool Water plant. All the principal tasks of operating the plant will be incorporated into the simulator. For training purposes, 31 preprogrammed malfunctions will be provided to simulate the problems that can occur while operating the plant. The system will use an advanced minicomputer with graphic work stations for both operator and instructor consoles. Delivery of the hardware and software is scheduled for late 1988, and the simulator is scheduled to be operational in early 1989.

The Cool Water Coal Gasification Program submitted a proposal to the Department of Energy on May 23, 1988, for continued operation under DOE's Program Opportunity Notice for Innovative Clean Coal Technology Demonstration Projects. The request for federal assistance was necessary for the project to proceed with IGCC development beyond the end of the original five-year plan (to be complete in mid 1989).

Key elements of the proposed four-year extended demonstration include modifications to the sulfur removal unit to further reduce emissions, extensive high-sulfur coal testing, production of methanol from coal-derived syngas, and the manufacture of synthetic lightweight aggregate from slag for use as a construction material.

Methanol is currently used as a chemical feedstock and has great potential as a transportation fuel to reduce air pollution. Of particular interest to utilities is methanol's use as a clean peaking fuel. An IGCC plant could produce methanol during low electricity demand periods and then burn it during peak periods. DOE project selections should be announced by November 1, 1988.

Work has continued at Cool Water to improve the reliability, energy efficiency, and environmental performance of IGCC power generation. Successful operation of the plant on two high-sulfur eastern coals, a low-sulfur Utah coal, and a high-ash-fusion-temperature Australian coal has demonstrated the applicability of the process to a wide range of coals. Owners of second-generation IGCC facilities can look forward to more flexibility in their procurement of coal feedstocks. The project has proved the feasibility of IGCC power generation and, by its continuing success, is reducing the real and perceived risks to future financiers and owners of IGCC facilities.

Land and Water Quality

Leaching Chemistry of Combustion Residues

by Ishwar P. Murarka, Environment Division

Each year the electric utility industry generates 80 million metric tons of solid residues, primarily from the combustion of fossil fuels. Most of this waste is disposed of in some 1000 landfills or ponds. Environmental regulations to protect groundwater against contamination by potentially toxic components of combustion wastes are placing constraints on current waste management practices. Moreover, groundwater protection strategies being formulated may result in even greater constraints and increase the amount of documentation required to demonstrate compliance.

It is in the industry's interest to develop the most cost-effective methods for disposing of waste and monitoring the environmental fate of waste components. Unfortunately, the available data and environmental process models have been insufficient for making accurate assessments of how groundwater quality is affected by the release of chemicals from utility waste disposal facilities.

After receiving input from industry representatives and academicians at four planning meetings and a workshop in 1981 (EA-2415), EPRI decided that an integrated research project was the most effective way to address this shortcoming. The SWES project (RP2485) was designed as an immediate response to meet the challenge. It encompasses the following research efforts:

- Leaching chemistry studies (RP2485-4, RP2485-8)
- Chemical attenuation studies (RP2485-3, RP2485-13)
- Subsurface transport studies: saturated zone dispersion (RP2485-5) and unsaturated-zone dispersion (RP2485-6)
- Geohydrochemical model evaluation and interim development (RP2485-2, -15)
- Field sampling method evaluation and improvement (RP2485-7, -11)
- Field validation of predictive methods (RP2485-9)
- Development of improved geohydrochemical models

The SWES effort is placing considerable emphasis on models because they are an effective way of using data to answer questions that face the industry. Eventually, the improved fundamental understanding gained through research will be incorporated into sophisticated mechanistic models for predicting the environmental fate of solutes. These improved models will be validated with field data from utility industry waste disposal sites.

To date, the SWES research has delivered an evaluation of existing predictive models (EA-3417); two interim models, MYGRT and FASTCHEM* (EA-4543-CCM, EA-5870-CCM, EA-5871, EA-5872), for evaluating the migration and fate of the inorganic constituents of wastes; and, most recently, an interim leaching model, FOWL* (EA-5742-CCM). In addition, several chemical attenuation models for individual elements (e.g., CHAT, CADAT, SEAT, ARSAT, VANDAT) will be delivered during the next three years. SWES researchers have also been conducting experiments to quantify waste leaching characteristics (EA-4215, EA-5321, EA-5922, EA-5923), dispersion/dilution through physical processes (EA-4082, EA-5816), and attenuation through geochemical transformation during transport (EA-4544, EA-5741).

SWES research has already proved useful. The EPA cited the work in its March 1988 report to Congress, and the Utility Solid Waste Activities Group (USWAG) has relied heavily on SWES results in responding to regulatory proposals that could affect the utility industry.

A special report (EA-5322-SR) published in August 1987 describes the SWES research in detail and discusses the results available through June 1987. This article provides a status update, focusing on the leaching chemistry of inorganic constituents in utility fossil fuel combustion residues.

*FASTCHEM and FOWL are EPRI trademarks.

Laboratory work on geochemical reactions

Predicting changes in groundwater quality associated with any waste disposal practice requires a knowledge of the leaching characteristics of the solid waste. There are three key questions: (1) what chemical concentrations will occur in leachates, (2) at what rates could waste constituents be released at a disposal facility, and (3) how long will leaching occur? EPRI selected Battelle, Pacific Northwest Laboratories to address these and other, related questions (RP2485-8). Project tasks are to evaluate the literature for data and methods used in quantifying leachate chemistry; to conduct laboratory and field experiments to develop mechanistic data on leaching chemistry; and to develop mathematical relationships and computer codes for quantitatively predicting chemical concentrations and release durations.

ABSTRACT *Protecting groundwater from contamination at disposal sites for fossil fuel combustion residues is an important utility concern. Through the solid-waste environmental studies (SWES) project, initiated in 1982, EPRI is sponsoring an extensive program of laboratory and field research to develop data and methods for predicting how disposal practices can affect groundwater quality. SWES results have already proved useful to utilities and government agencies in addressing waste disposal issues. One major research focus is the leaching chemistry and release mechanisms of inorganic constituents. Progress in this area includes the development of an interim model on leachate generation.*

Leachate chemistry is controlled by three major processes: precipitation/dissolution, adsorption/desorption, and oxidation state transformation. The studies of release mechanisms are focused on relating leaching chemistry to these fundamental processes. Battelle is conducting laboratory experiments to quantify the factors that control concentrations of inorganic elements in leachate produced at waste disposal sites over the short and the long term.

In studies already completed, the researchers selected four fly ashes with a wide range of chemical properties (Table 1). Subsamples of the wastes were suspended in water, adjusted to a range of pH values from 2 to 14, and allowed to react for different lengths of time. The aqueous concentrations of almost all the elements in the wastes reached a steady state in less than seven days. Several elements (aluminum, barium, calcium, chromium, copper, strontium, sulfur, and zinc) exhibited pH-dependent solubility. Although the wastes differed considerably in terms of both pH and bulk chemical composition, the aqueous concentrations of each of these elements were similar, and ionic activity showed quantitative similarity as a function of the pH of the leachate. Figure 1 presents the results for aluminum.

Two important conclusions can be drawn from these results. First, even when there are substantial differences in the element-specific composition of fly ashes, the reactions controlling the concentrations in leachates from these ashes are essentially the same (EA-5321). Second, the concentrations can be associated with specific chemical reactions, which in turn can be used in predicting leachate composition (EA-5742-CCM).

In addition to the results for the elements cited above, it was found that aqueous concentrations of vanadium, selenium, and molybdenum ranged over three to four orders of magnitude as a function of pH. For these elements, the highest observed aqueous concentrations were within one order of magnitude of the concentrations that would have occurred if the total amount present in

Table 1
CHEMICAL COMPOSITION OF WASTES

	Total Concentration in Sample			
Element	Sample 1	Sample 2	Sample 3	Sample 4
Aluminum (%)	10.3	12.6	9.3	14.0
Calcium (%)	1.07	0.91	3.34	0.95
Iron (%)	17.7	8.2	13.7	6.5
Sulfur (%)	0.95	0.37	0.77	0.49
Arsenic (μg/g)	126.0	204.0	15.0	171.0
Barium (μg/g)	367.0	783.0	425.0	984.0
Chromium (μg/g)	294.0	170.0	441.0	141.0
Copper (μg/g)	139.0	202.0	90.0	165.0
Molybdenum (μg/g)	97.0	41.0	60.0	31.0
Selenium (μg/g)	<3.0	7.5	9.0	10.4
Strontium (μg/g)	261.0	1092.0	327.0	746.0
Vanadium (μg/g)	459.0	315.0	254.0	243.0

Note: At a wasteto-water ratio of 1:20, the pH for sample 1 was 3.30; for sample 2, 6.03; for sample 3, 11.75; and for sample 4, 7.34.

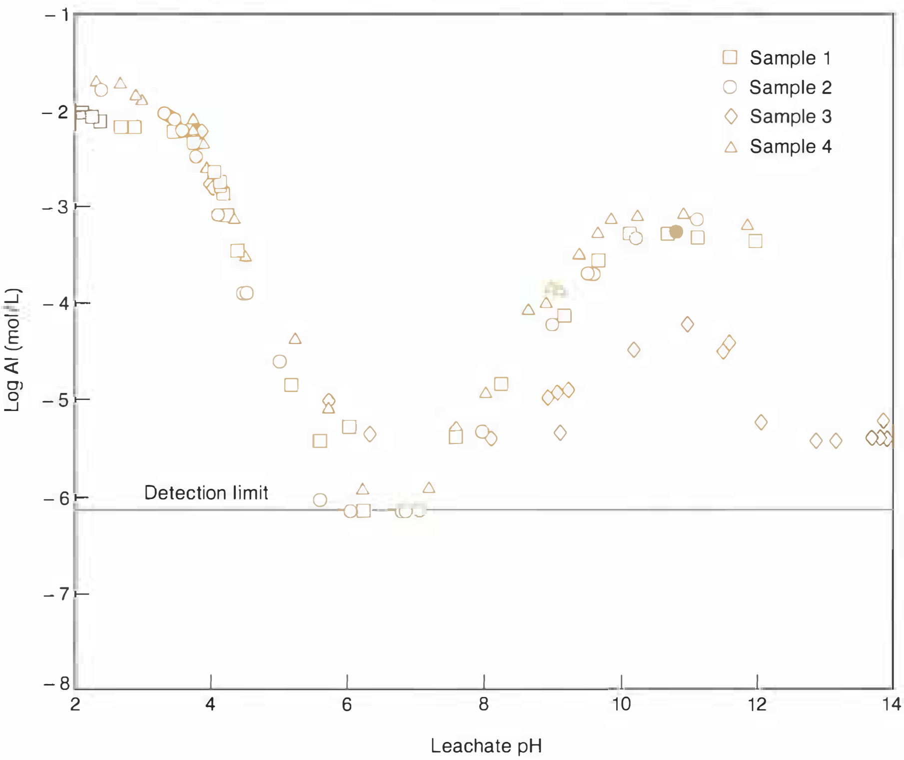


Figure 1 Concentration of aluminum in leachates from four fly ash samples. Even though the ashes differed in pH and chemical composition, the aqueous concentrations of aluminum varied similarly as a function of the leachate pH. Several other elements also showed pH-dependent solubility.

the solid phase had dissolved. The results indicate that a significant portion of these elements is likely to be leached when waste is combined with water at a disposal site. The results also demonstrate that the aqueous concentration of an individual element is dependent on its reaction chemistry and the hydrologic environment rather than on the total amount found in the waste.

Studies are under way to identify and quantify the solid mineral phases that determine the amount and duration of leachate formation from waste disposal sites. Twenty large samples of fly ash, bottom ash, scrubber sludge, and oil ash from eight power plants will be used for intensive laboratory experiments on the leaching processes. In future experiments, researchers will seek to establish time-dependent release rates as controlled by equilibrium or kinetic reactions. To address long-term mobilization and leaching, field measurements at disposal sites ranging in age from 20 to 45 years are to begin early next year. Completion of this research is slated for 1993.

Fly ash field data

Since 1984, EPRI has collaborated with Pennsylvania Power and Light (PP&L) on leaching chemistry research at a fly ash test cell the utility constructed at its Montour power plant. Initially EPRI focused on evaluating the performance of hydrologic measurement methods (EA-5011) while PP&L focused on water balance studies and assessment of water quality from surface runoff and leachate generation. During late 1987 and early 1988, additional pore waters and leachates were collected and analyzed under PP&L and EPRI sponsorship.

The field data were compared with laboratory data from RP2485-8 to see whether solubility controls documented in the laboratory were relevant to the leaching chemistry of inorganic constituents of coal fly ash in a field disposal setting. A geochemical model, MINTEQ, was used to analyze the data. The analyses indicated that the leachate concentrations of several elements (aluminum, barium, calcium, chromium, copper, iron, sulfur, strontium, and possibly silicon) are controlled by specific solid phases. Several other trace elements (arsenic, boron, cadmium, molybdenum, and selenium) could not be associated with the solubility of specific solid phases (EA-5922); ongoing research will address this shortcoming. These results demonstrate that a mechanistic approach can be successfully used in predicting the short-term leaching of several inorganic constituents of fossil fuel combustion wastes.

FGD sludge field study

Battelle researchers have recently completed a field investigation of a flue gas desulfurization (FGD) disposal site (EA-5923). The objectives of this field work were (1) to refine the sampling, field measurement, and analytical techniques necessary for field applications of laboratory-derived geochemical data, (2) to identify the reactions involved in the long-term chemical leaching of wastes, and (3) to provide field measurements of solute attenuation for comparison with laboratory predictions. This field investigation has helped ensure that the laboratory research focuses on real-world phenomena.

At the disposal site, located in the midwestern United States, FGD sludge ($CaCO_3$ base) from a Venturi scrubber was slurried onto the land surface about seven years ago and surrounded by an ash dike. The underlying soils are fine-grained and montmorillonitic, and the sludge surface is partly revegetated. The sludge shows physical stratification, with the occasional inclusion of ash. At present, it is oxidized to a depth of 45.7–66.0 cm, below which the material is water-saturated and thixotropic.

After a preliminary survey, the researchers conducted detailed sampling by using a floating drilling rig equipped with a rotary auger core. They collected continuous cores of sludge and underlying subsoil to depths of 15 m from the surface. A specialized probe constructed for this research was used to make in situ redox potential and pH measurements at various depths in the sludge. All cores were sealed at the site and then refrigerated until analysis.

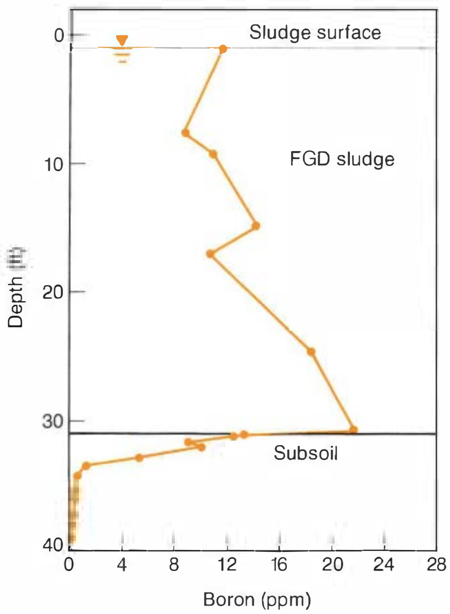
In the laboratory, redox potential and pH were remeasured under nitrogen gas atmosphere to confirm the field measurements. Pore waters were carefully extracted, filtered under nitrogen gas, and subjected to detailed analysis for major and minor dissolved chemical constituents. X-ray diffraction and fluorescence methods were used to determine the mineralogic and total chemical composition of the sludge. Fungi and heterotropic, denitrifying, and sulfate-producing bacteria were identified—both in samples of fresh sludge from a new pond and in samples of old sludge at various depths in the basin.

Pore waters in the sludge were found to be chemically reduced and contained several sulfur species. Possibly because of precipitation with sulfide, trace metals were below detection levels. Levels of dissolved organic carbon were high (100–200 ppm). For the minor constituents, the most elevated aqueous concentration over the background soil level occurred for boron in the first meter of soil below the sludge (Figure 2).

Thermodynamic calculations and direct chemical analysis verified the association of specific solids in the sludge to specific controlling reactions, explaining observed leachate concentrations of such major constituents as calcium, magnesium, strontium, and sulfate. The presence of microbes was correlated with the distribution of reduced sulfur and nitrogen, thereby confirming the role of specific microorganisms in the long-term evolution of reduced conditions in the wastes. Because of the low permeability and high geochemical reaction capacity of the underlying soils, solute transport beneath the sludge was attenuated. Migration into the subsoil ranged from 2 m for soluble salts to 1 m for boron.

This field study has clarified some of the chemical reactions occurring in FGD sludge disposal ponds. Although only one site has been investigated, the physicochemical similarity of FGD sludges suggests that most of the observations made here are likely to be applicable to other sites. More important, the study has established improved protocols for waste site sampling and the chemical analysis of field samples. Given careful sample preservation and analysis, the mechanistic data developed in the SWES chemical attenuation and leaching chemistry studies could be used to interpret and predict leachate composition.

Figure 2 Concentration of boron in pore waters extracted from samples at an FGD sludge disposal site. Below the sludge-soil boundary the concentrations are elevated above the normal background soil level, indicating that boron has migrated 1 m (~3 ft) into the subsoil.



Leachate generation model

Under RP2485-8 Battelle has developed an interim model that simulates the leachate formation process in solid waste (EA-5742-CCM). Called FOWL (for fossil fuel combustion waste leaching), the model is a mechanistic and semiempirical computer code for predicting leachate concentrations of selected inorganic elements found in fossil fuel combustion wastes. The development effort builds on a critical review of the literature (EA-5176) and on the SWES experimental and field work. The model uses data developed in the early SWES laboratory studies, a characterization of 99 samples from 46 power plants (EA-5321), a detailed study of leachates at two field sites, the study at the FGD sludge disposal site described above, and work at the Montour fly ash test cell.

FOWL has mechanistic submodels for Al^{+++}, Ba^{++}, Ca^{++}, $CrOH^{++}$, H_4SiO_4, Sr^{++}, MoO_4^{--}, and SO_4^{--}. It uses semiempirical submodels for As, B, Cd, Cu, Fe, Mg, Na, Ni, Se, and Zn. The waste is treated as a homogeneous medium. For each chemical, the model calculates the total amount that can be leached, as well as concentrations in the leachate as a function of time. The user specifies the initial chemical composition and physical properties of the waste (i.e., porosity, initial moisture content, saturated moisture content, and physical dimensions), the composition of the rainwater, and the rainwater flux (net infiltration). If the composition of the waste or the rainwater is unknown, the user can choose from among several typical compositions.

The FOWL model is designed to run on an IBM PC with an arithmetic coprocessor. The results of a computer run are stored in a file that can be viewed on the screen or printed. Output can be presented in graphic form if the computer has a graphics card. A hard disk facilitates program use but is not essential. The model includes data bases for coal fly ash, coal bottom ash, FGD sludge, and oil ash. FOWL was tested in prerelease form in early 1988 by members of EPRI's Science Advisory Committee for Land and Water Quality Studies. It is now available as a commercial product from EPRI's Electric Power Software Center.

Technology transfer

To encourage use of the SWES results, EPRI sponsored annual technology transfer seminars in 1984, 1985, and 1986 and six regional seminars in 1987; a seminar on FOWL is scheduled for this October. In addition, SWES contractors have written many technical journal articles, and EPRI staff and contractors have presented numerous briefings to regulators, scientists, utility representatives, and the public at large. EPRI continues to provide member utilities with technical assistance in applying SWES results to site-specific problems.

The SWES research has addressed some of the key issues relating to land and water quality with which electric utilities must deal. Regulatory developments under the Safe Drinking Water Act and the Resource Conservation and Recovery Act have intensified the need for information on water contamination by inorganic and organic chemicals. The ongoing SWES research, together with the EBOS (environmental behavior of organic substances) project (RP2879), will continue to support utilities in developing cost-effective plans for controlling or correcting groundwater contamination at disposal sites.

Piping Erosion-Corrosion

Predicting Pipe-Wall Erosion Rates

by V. K. Chexal, R. Jones, and T. Passell, Nuclear Power Division, and S. Gehl, Coal Combustion Systems Division

In December 1986, an 18-in condensate system elbow fitting ruptured at a U.S. nuclear power station. This accident was the result of pipe-wall thinning (metal loss) caused by flow-assisted corrosion. This phenomenon, erosion-corrosion, is complex and depends on the interrelationships of water temperature, water chemistry, alloy content of the pipe material, flow velocity, and the geometry of the flow path (e.g., straight, bend, tee).

Another instance of pipe rupture caused by single-phase erosion-corrosion occurred under similar conditions at a fossil fuel plant in 1982. Because of the seriousness of pipe ruptures in high-pressure lines and the potential for such ruptures to occur at any plant, there was an urgent need to find ways of predicting erosion-corrosion rates to help prevent further pipe failures. The challenges to EPRI were (1) to find ways to determine where single-phase erosion-corrosion has most likely occurred in in-service piping, (2) to define accurate and low-cost methods of inspection, and (3) to identify techniques for preventing further pipe degradation.

The Nuclear Management and Resource Council (NUMARC) and EPRI designed an inspection plan. The key elements of the plan are to identify where to inspect, how to inspect, when to inspect, and how to respond. The plan is designed to provide utilities with the ability to predict wall thickness as a function of plant life for a given component and to assess the costs and benefits of a variety of remedial options.

EPRI's role has been twofold: to develop and transfer to the utilities the technical products needed to resolve the problem (e.g., computer codes and reports) and to provide full product support (e.g., training, telephone hot line, workshops).

The centerpiece of EPRI's effort has been the development of a predictive computer program, CHEC (Chexal-Horowitz erosion-corrosion), that uses plant-specific data to predict the extent of metal loss in various piping components. The CHEC program, which is based on extensive laboratory test data from Europe and the United States, helps to avoid wholesale, random, and nonproductive inspection efforts.

The program is used on a personal computer and is designed to be a flexible and comprehensive analytic tool that is easy to use. It incorporates an interactive user-

ABSTRACT *Flow-accelerated corrosion, which causes thinning of the walls of steel piping, has been implicated in ruptures of large-diameter piping at power generating plants. However, a new EPRI computer program, CHEC, is now available that can accurately predict the rates at which pipe walls are eroded, thus providing plant operators with an improved capability of preventing such failures.*

interface that provides guidance to the user during data entry or problem analysis.

The results from CHEC erosion-corrosion calculations are provided in printed reports and in displays and plots. (A sample is shown in Figure 1.) The displays make it possible to review the results quickly, identify possible anomalies in the results, and refine the plant data input file to represent plant conditions accurately. The displays also make it easier to evaluate the effect of design changes or new design options.

CHEC provides the information necessary for a utility to develop a cost-effective inspection program to determine the extent (if any) to which piping components have been thinned, as well as the scheduling and planning of future inspections. The program assists the user in several ways.

- Providing guidance on where to begin the inspection by ranking components in the piping system in the order of susceptibility to damage by erosion-corrosion, as well as in the order of remaining lifetime
- Using data from the initial inspection of 10 or more locations to develop a plant-specific erosion-corrosion model
- Using this plant-specific model to refine the ranking of locations and to provide quantified estimates of erosion-corrosion rates and the times at which minimum allowable wall thicknesses are reached

Additional applications include conducting parametric studies to determine the effect of changing water chemistry, pipe size, piping layout, and pipe materials on piping life; and designing new piping systems that are less likely to be damaged by erosion-corrosion. CHEC has a total capacity of 1500 piping components per run.

The general formulation of the model used is a series of factors the product of which is the predicted erosion-corrosion rate. Because some of the factors are interrelated, the model is not linear. The factors are the effects of temperature, alloy content, mass transfer (flow rate, pipe diameter), oxygen, pH (amine type), and component geometry.

Because the interrelations between these parameters were not apparent initially, the formulation was developed empirically. In doing so, all six factors were incorporated into the model, and all the available data were used in the model development. The model did not presuppose a form of the correlation, and although the model is empirical, steps were taken to ensure that each part of the model made mechanistic sense. In accordance with these principles, a data base was assembled by using inputs from various laboratories. An interactive procedure was used with the data base until an optimal model was obtained. This model followed all the experimental trends and correlated well with a preponderance of the laboratory data.

The model was further refined by comparing its predictions with data obtained from nuclear power plants and with additional laboratory data. These new data—particularly those that made it possible to take into account various geometric mass transfer enhancement factors—resulted in an improved model that has been released as Version 1.2 of CHEC.

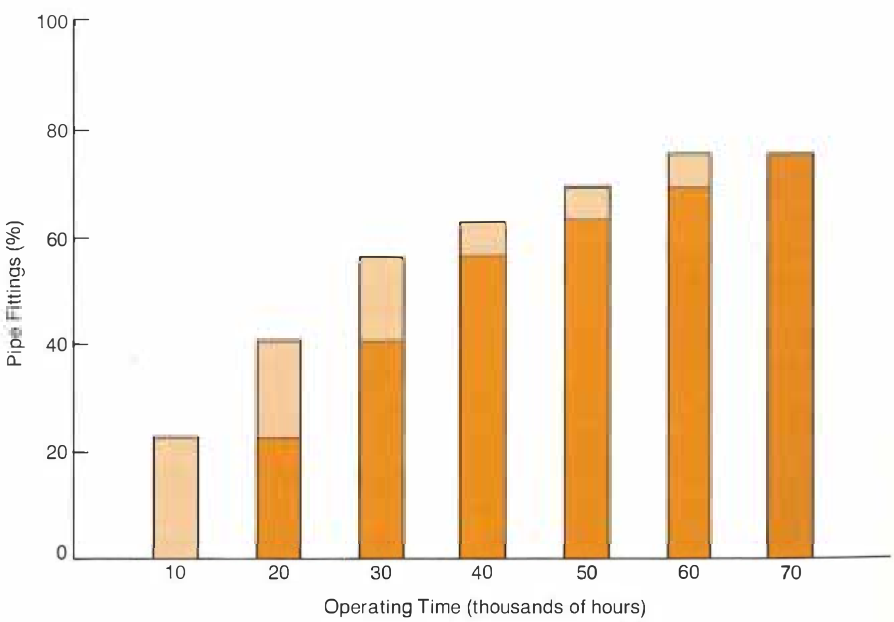


Figure 1 In this sample problem, CHEC has calculated the cumulative percent of pipe fittings that will reach the minimum allowable wall thickness over an operating time of 70,000 hours.

The correlation between predictions of CHEC, Version 1.2, and plant inspection results has been very good. The ability of the program to predict single-phase erosion-corrosion rates within a ±50% band, given accurate input data, has been demonstrated. This performance is better than that achieved with other known erosion-corrosion correlation prediction techniques; moreover, CHEC is continually being made more accurate by data and analysis feedback from CHEC users at U.S. nuclear and fossil fuel power plants.

Fifty-two U.S. utilities now have the CHEC code, and a total of 150 nuclear and fossil fuel plants are expected to be using CHEC by December 1988. Several utilities in other countries are also using CHEC. Thus the industry now has the knowledge and the tools needed to protect against the erosion-corrosion phenomenon.

Plant Availability

GADSRAM: A Method to Facilitate Availability Assessment

by Jerome Weiss, Advanced Power Systems Division

ABSTRACT *A new software tool called GADSRAM makes it easier to perform generating-unit availability analyses with the UNIRAM methodology. GADSRAM quickly converts plant performance and outage data in NERC GADS (the North American Electric Reliability Council's Generating Availability Data System) to the format necessary for UNIRAM, a task that used to be time-consuming and costly. Moreover, GADSRAM greatly facilitates the development of plant availability models for UNIRAM. With the data and models generated by GADSRAM, UNIRAM can be used to assess the potential availability effects of changes in plant configuration, components, or maintenance.*

GADSRAM is a method that greatly facilitates the availability evaluation of generating units for which design and operating data are available in NERC GADS—the Generating Availability Data System. GADS is maintained by the North American Electric Reliability Council and is supported by funds and data from most utilities in Canada, Mexico, and the United States. GADSRAM uses GADS data to develop an availability model for the operating plant from which the data derive and to enable availability evaluations of the plant with the UNIRAM methodology (Figure 1).

The development of GADSRAM (derived from the acronyms NERC GADS and UNIRAM) was undertaken at the urging of several utilities who also participated by providing direction, review, cost-sharing, and testing of the product: Boston Edison, Consolidated Edison, Northeast Utilities, and Southern California Edison. ARINC Research performed the work.

The NERC GADS information base

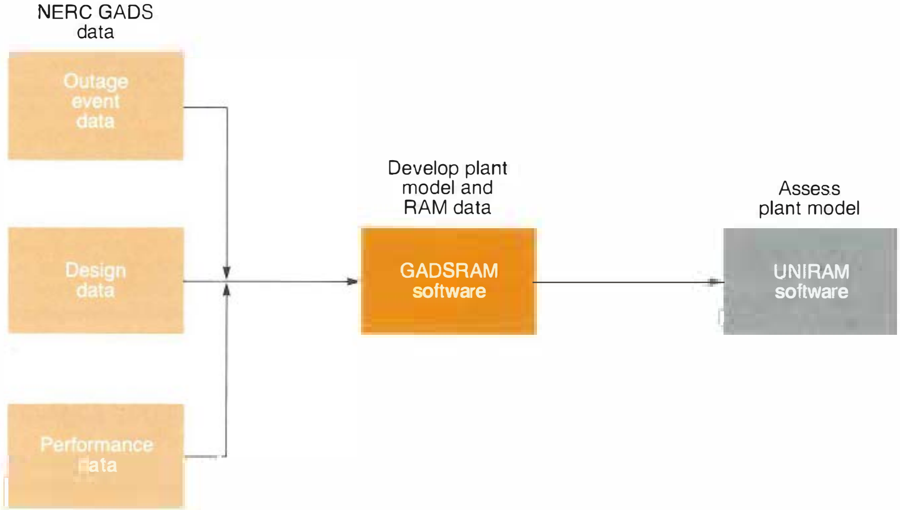
Most utilities in North America are a part of NERC and supply data on their generating units to the GADS central system. The information supplied to NERC GADS by the utilities includes quarterly performance data (e.g., total operating, derated, reserve shutdown, and scheduled outage hours) and unit failure information (e.g., components responsible for failure, time of failure, duration of outage or derating, and magnitude of derating). Utilities also provide data relating to plant configuration, such as numbers, sizes, and types of components. These categories of information are supplied in computer-readable form and are maintained in that form in GADS.

In addition, GADS processes individual plant input to produce the specialized and general data regularly reported to the industry and the public. Utility members also have access to GADS facilities to request special runs or analyses of the data bank.

GADSRAM

The plant operating data received and maintained by GADS are not in a form immediately suited for use in the UNIRAM availability assessment model. For example, GADS contains the beginning and end times and dates of an event; UNIRAM requires as input the data derived from the number of

Figure 1 The GADSRAM methodology facilitates availability analysis in two main ways: it quickly converts NERC GADS generating-unit data to the necessary format, and it streamlines the process of plant model development. The data and model generated by GADSRAM are then used by the UNIRAM software to assess plant availability.



events and the time elapsed between the beginning and end of individual events—that is, mean time between failure and mean downtime data.

The conversion of data from NERC GADS, which is the best source of data for availability analyses, requires extensive reformatting, a time-consuming and costly process. GADSRAM makes this conversion automatically and quickly; a project that may have taken several person-weeks becomes one that takes a few minutes on a personal computer.

GADSRAM further facilitates analysis by automating the development of an availability model. This part of the availability analysis process may take an experienced model builder from one to four weeks. Using GADSRAM, a modeler can automatically and interactively construct a preliminary availability model that reflects the configuration of the unit to be evaluated. If the configuration of the unit is straightforward, this model may be accurate and complete. If the configuration is more complex, the analyst can modify the preliminary version to produce a more accurate model. For an experienced analyst who is familiar with the unit, this process can be done interactively and quickly. Once built, the model can be used during the life of the unit and for similar units. Changes can be readily incorporated without reprogramming the entire model.

GADSRAM software features

The GADSRAM software was developed on a modular basis: five basic modules allow the user to create and update availability models and view or print output files generated by the software (Figure 2). These modules and their functions follow:

▫ Data conversion: This module converts NERC GADS outage event and performance data into a form required by GADSRAM.

▫ Plant configuration development: This module, using the NERC GADS plant design data file and information gained from user interaction, develops a set of rules for generating the availability model logic structure and for calculating the required reliability, availability, and maintainability (RAM) data.

▫ Model development: This module generates a UNIRAM data input file.

▫ Output: This module allows the user to view or print various files generated by the GADSRAM software. Key files include (1) a listing of the RAM statistics generated, along with their 90% confidence bounds, (2) the UNIRAM data input file generated by the GADSRAM software, and (3) availability block diagrams (ABDs) and fault trees, drawings of the model that are generated from the UNIRAM data input file. (This option can be used to generate ABDs and fault trees for any UNIRAM data input file.)

▫ GADSRAM setup: This module enables the user to specify the computer hardware environment, software color schemes, and data file libraries.

Advantages

GADSRAM offers an easy way to construct an availability model for any generating unit for which a utility has developed GADS data. This model and the GADS data can be used to review the availability characteristics of the unit and to conduct "what if" analyses to explore the effects on availability of changes in configuration, component quality, and maintenance policies or practices.

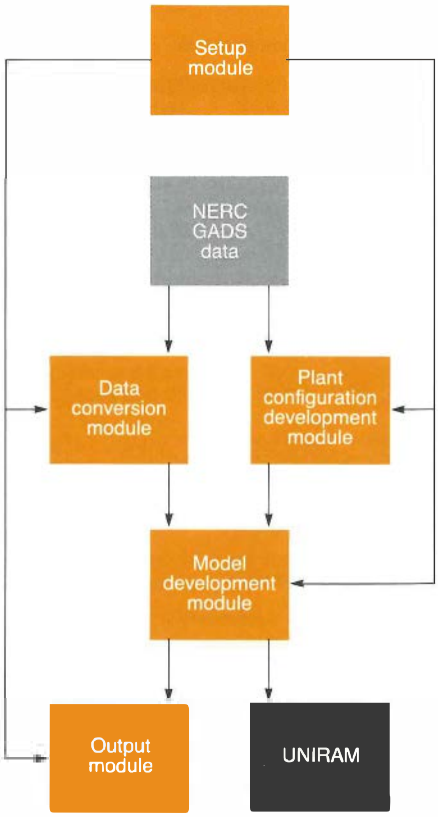


Figure 2 Five modules make up the GADSRAM software. Using NERC GADS data, the software develops RAM statistics and plant models for use in availability analyses with the UNIRAM methodology.

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Advanced Power Systems		
Photovoltaics: Light-Induced Instability of Hydrogenated Amorphous Silicon (RP1193-11)	$202,300 11 months	Stanford University/ *T. Peterson*
New Technology for Extracting Pure Oxygen From Pressurized Air (RP1676-11, RP8002-16)	$75,000 12 months	Westinghouse Electric Corp./*R. Goldstein*
CAES Plant With Steam Generation: Preliminary Design and Cost Analysis (RP2676-3)	$165,200 19 months	Energy Storage and Power Consultants/ *R. Pollack*
Compressed-Air Energy Storage (CAES) Plant (RP2894-1)	$4,900,000 56 months	Alabama Electric Cooperative/*R. Schainker*
Development of a Concrete Gravity Dam Analysis Processor (RP2917-12)	$146,500 16 months	Anatech Research Corp./ *D. Morris*
Engineering Model of Mixing Processes in Residual Fuel Oil Storage Tanks (RP2947-2)	$87,000 4 months	Energy Systems Associates/*W. Rovesti*
High-Concentration Photovoltaic Module, Cell, and Material Testing (RP2948-9)	$32,600 6 months	DSET Laboratories, Inc./ *J. Bigger*
Coal Combustion Systems		
Demonstration of Pulse-Jet Fabric Filter Technology (RP1129-20)	$40,000 1 month	Howden Environmental Systems, Inc./*R. Chang*
Flue Gas Desulfurization Cycling Guidelines (RP1184-30)	$175,800 14 months	Sargent & Lundy/ *P. Radcliffe, G. Poe*
Demonstration of DYNAMICS for Economic Analysis of Cycling Modifications (RP1184-31)	$65,000 7 months	Decision Focus, Inc./ *G. Poe*
Demonstration of a Laser Optic Profilometer for Boiler Tube Inspection (RP1865-11)	$88,000 6 months	Flow Research, Inc./ *S. Gehl*
Status of Municipal Refuse–to–Energy Technology (RP2190-4)	$69,100 7 months	Battelle Memorial Institute/*C. McGowin*
Development of Steam Sampling (RP2712-8)	$107,500 24 months	Jonas, Inc/*B. Dooley*
Stochastic Modeling of Chemical Emissions From Former Generating Systems (RP2933-2)	$135,600 18 months	Carnegie-Mellon University/*W. Chow*
Data Base on Emerging Treatment Technologies (RP3006-3)	$64,400 13 months	Precor Corp./*M. McLearn*
Electrical Systems		
Methods for High-Impedance Fault Detection (RP1472-4)	$236,000 15 months	Texas A&M Research Foundation/*T. Kendrew*
Static Electrification Monitoring (RP1499-13)	$152,700 18 months	Electric Research & Management, Inc./*S. Lindgren*
Innovative Power System Control Concepts (RP2473-30)	$109,200 1 month	Massachusetts Institute of Technology/ *D. Maratukulam*
Rotor-Bar Thermal Monitoring in Large Asynchronous Machines (RP2591-10)	$59,300 4 months	Spectra Technology, Inc./ *J. Edmonds*
Rotor-Mounted Scanner for High-Speed Turbine Generators (RP2591-11)	$58,000 4 months	Spectra Technology, Inc./ *J. Edmonds*
Use of Expert Systems in Transient-Energy-Function Applications (RP2944-3)	$65,800 12 months	McMaster University/ *G. Ben-Yaacov*
Energy Management and Utilization		
Indoor Air Quality (RP2034-25)	$50,000 12 months	Geomet Technologies, Inc./*J. Kesselring*
Demand Control of Commercial Buildings (RP2480-10)	$49,000 8 months	Analysis & Control of Systems, Inc./*L. Carmichael*
Development of Small-Cogenerator Data Base (RP2950-1)	$146,000 11 months	Synergic Resources Corp./*H. Gransell*
Power System Disturbances (RP2951-8)	$66,600 13 months	Michigan State University/ *M. Samotyj*
Screening Model for Electric Alternatives to Cogeneration (RP2983-3)	$75,300 7 months	Regional Economic Research/*M. Blatt*
Identification of Finite-State Machines (RP8000-32)	$150,700 23 months	Columbia University/ *L. Carmichael*
Correlation of Ash Fouling Tendencies and Gas-Phase Sodium Atom Concentrations (RP8005-8)	$26,900 9 months	University of North Dakota/*A. Mehta*
Bubble Mechanism of Tube Erosion in Fluidized-Bed Combustors (RP8006-13)	$282,700 23 months	Lehigh University/*E. Petrill*
Monomers That Expand on Polymerization (RP8007-2)	$180,000 21 months	Westinghouse Electric Corp./*B. Bernstein*
Intelligent-Computer-Aided Engineering in Power Plants and Systems (RP8010-2)	$60,000 9 months	Texas Engineering Station/*R. Colley*
Environment		
Northern Hemisphere Glaciochemical/ Greenhouse Gas Time Series (RP2333-3)	$280,000 23 months	University of New Hampshire/*L. Levin*
Studies of Interactions of Organic and Inorganic Solutes (RP2485-13)	$346,600 31 months	Stanford University/ *I. Murarka*
Risk Perception and Risk Communication Regarding Electromagnetic Field Exposure (RP2955-3)	$200,000 7 months	Carnegie-Mellon University/*C. Whipple*
Developing Risk Scales (RP2955-5)	$60,800 5 months	University of Southern California/*C. Whipple*
Electric and Magnetic Field Exposure Associated With Electric Blankets (RP2966-3)	$102,900 21 months	Carnegie-Mellon University/*S. Sussman*
Molecular Biology: Biodegradation of Polyaromatic Hydrocarbons (RP3015-2)	$50,000 12 months	University of Iowa/ *R. Goldstein*
Nuclear Power		
Nuclear Construction Issues Group: Selective Acceptance Inspection Program (RPQ101-12)	$45,500 4 months	Sargent & Lundy/ *W. Bilanin*
Resin Leakage Analyzer Development (RPS401-9)	$58,000 10 months	Carter Analytical Laboratory, Inc./*T. Passell*
Belgian Approach to Steam Generator Tube Plugging (RPS404-14)	$64,500 10 months	Belgatom/*A. McIlree*
Susceptibility of Alloys 600 and 690 to Acid Sulfate Solutions (RPS407-25)	$380,300 26 months	Materials Engineering Associates, Inc./ *C. Shoemaker*
Susceptibility of Alloys 600 and 690 to Acid Sulfate Solutions (RPS407-28)	$59,500 26 months	Dominion Engineering, Inc./*C. Shoemaker*
Enhancement of the MULTEQ Computer Code (RPS407-30)	$42,900 3 months	S-Cubed/*P. Paine*

New Technical Reports

Requests for copies of reports should be directed to Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081. There is no charge for reports requested by EPRI member utilities, U.S. universities, or government agencies. Others in the United States, Mexico, and Canada pay the listed price. Overseas price is double the listed price. Research Reports Center will send a catalog of EPRI reports on request. For information on how to order one-page summaries of reports, contact the EPRI Technical Information Division, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2411.

ADVANCED POWER SYSTEMS

Practical Feasibility of Advanced Steam Systems for Combined-Cycle Power Plants
AP-5815 Final Report (RP2052-2); $32.50
Contractor: Bechtel Group, Inc.
EPRI Project Manager: A. Cohn

Altamont Wind Power Plant Evaluation for 1986
AP-5824 Final Report (RP1590-6); $25
Contractor: Pacific Gas and Electric Co.
EPRI Project Manager: J. Schaefer

Residual Fuel Oil User's Guidebook, Vols. 1–4
AP-5826 (RP2106-2); Vol. 1, $32.50; Vol. 3, $32.50; Vol. 4, $32.50; Vol. 2, forthcoming
Contractor: Southwest Research Institute
EPRI Project Manager: H. Schreiber

Design and Costs for a Generic 10-MW Utility Lead-Acid Battery Energy Storage Plant
AP-5845 Final Report (RP2123-6); $40
Contractor: Bechtel Group, Inc.
EPRI Project Manager: D. Morris

Guide for Hydraulic Machinery Model Testing
AP-5876 Final Report (RP2602-1); $40
Contractor: Motor Columbus Consulting Engineers, Ltd.
EPRI Project Manager: D. Morris

COAL COMBUSTION SYSTEMS

Life Assessment Methodology for Turbogenerator Rotors, Vol. 1: Improvements to the SAFER Code
CS/EL-5593 Final Report (RP2481-3, RP2785-1); $500
Contractor: J. A. Jones Applied Research Co.
EPRI Project Managers: R. Townsend, R. Viswanathan, J. Edmonds

Life Assessment Methodology for Turbogenerator Rotors, Vol. 2: SAFER Code Engineering
CS/EL-5593 Final Report (RP2481-3, RP2785-1); $500
Contractor: J. A. Jones Applied Research Co.
EPRI Project Managers: R. Townsend, R. Viswanathan, J. Edmonds

Life Assessment Methodology for Turbogenerator Rotors, Vol. 3: SAFER Code Methodology
CS/EL-5593 (RP2481-3, RP2785-1); $500
Contractor: J. A. Jones Applied Research Co.
EPRI Project Managers: R. Townsend, R. Viswanathan, J. Edmonds

Life Assessment Methodology for Turbogenerator Rotors, Vol. 4: SAFER Code Computer Manual
CS/EL-5593-CCM Computer Code Manual (RP2481-3, RP2785-1); $500
Contractor: J. A. Jones Applied Research Co.
EPRI Project Managers: R. Townsend, R. Viswanathan, J. Edmonds

On-Line Eddy-Current Crack Monitor
CS-5694 Final Report (RP1894-1); $200
Contractor: General Electric Co.
EPRI Project Manager: J. Scheibel

Proceedings: Reducing Electricity Generation Costs by Improving Coal Quality
CS-5713 Proceedings (RP1400); $575
Contractor: Writing Consultants Associated
EPRI Project Managers: C. Harrison, J. Hervol

Condenser Performance Test and Back-Pressure Improvement
CS-5729 Final Report (RP1689-8); $200
Contractor: Heat Exchanger Systems, Inc.
EPRI Project Manager: J. Tsou

Multisystem Corrosion Monitoring in FGD Systems, Phase 2
CS-5734 Interim Report (RP1871-14); $200
Contractor: Corrosion and Protection Centre Industrial Services
EPRI Project Manager: B. Syrett

Multisystem Corrosion Monitoring in a Cyclic Reheat Test Facility, Phase 1
CS-5776 Interim Report (RP1871-17); $150
Contractor: Corrosion and Protection Centre Industrial Services
EPRI Project Manager: B. Syrett

Monitoring Technologies for Underground Storage Tanks
CS-5780 Final Report (RP2795-1); $100
Contractor: Roy F. Weston, Inc.
EPRI Project Manager: M. McLearn

Colorado-Ute Circulating AFBC Demonstration, Vol. 1: Project Origin
CS-5831 Final Report (RP2683-2); $25
Contractor: United Engineers & Constructors, Inc.
EPRI Project Manager: S. Tavoulareas

ELECTRICAL SYSTEMS

Nondestructive Evaluation of Wood Utility Poles, Vol. 2: Second-Generation Nondestructive Evaluation
EL-5063 Final Report (RP1352-4); $32.50
Contractor: Engineering Data Management, Inc.
EPRI Project Manager: P. Lyons

Laser Characterization of Cable Insulation
EL-5669 Final Report (RP794-6); $25
Contractor: United Technologies Research Center
EPRI Project Manager: J. Porter

Conductor Temperature Research
EL-5707 Final Report (RP2546-1); $32.50
Contractor: Georgia Institute of Technology
EPRI Project Manager: V. Longo

Proceedings: Transformer Overload and Bubble Evolution
EL-5807-SR Proceedings; $40
EPRI Project Managers: G. Addis, S. Lindgren

Proceedings: Generator Retaining-Ring Workshop
EL-5825 Proceedings (RP2719-1); $62.50
Contractor: J. A. Jones Applied Research Co.
EPRI Project Manager: J. Stein

ENERGY MANAGEMENT AND UTILIZATION

Stratified Chilled-Water Storage Design Guide
EM-4852 Final Report (RP2036-19, RP2732-13); $150
Contractors: Reid, Crowther and Partners, Ltd.; George Reeves Associates, Inc.
EPRI Project Managers: R. Wendland, C. Hiller

DSM Customer Response, Vol. 1: Residential and Commercial Reference Load Shapes and DSM Impacts
EM-5767 Final Report (RP2548-1); $1000
Contractors: Synergic Resources Corp.; Laurits R. Christensen Associates, Inc.; Battelle, Columbus Division
EPRI Project Managers: S. Braithwait, W. Smith

Secondary Data for Demand-Side Management Planning and Implementation, Vols. 1 and 2
EM-5806 Final Report (RP2050-11); Vol. 1, $32.50; Vol. 2, $32.50
Contractor: Synergic Resources Corp.
EPRI Project Manager: L. Lewis

Cool Storage Marketing Guidebook
EM-5841 Final Report (RP2050-11); $40
Contractor: Synergic Resources Corp.
EPRI Project Managers: L. Lewis, R. Wendland

Least-Cost Energy Planning in the Midwest: A Symposium
EM-5846 Proceedings (RP2982); $40
Contractor: Center for Regulatory Studies
EPRI Project Manager: P. Hanser

Developing Energy-Integrated Industrial Parks

EM-5853 Final Report (RP1276-5); $25
Contractor: Burns and Roe, Inc.
EPRI Project Managers: H. Gransell, W. Smith, T. Oldberg

ENVIRONMENT

Evaluation of Tracer Sampling Devices for the Macrodispersion Experiment

EA-5816 Interim Report (RP2485-5); $25
Contractor: Tennessee Valley Authority
EPRI Project Manager: I. Murarka

Boron Uptake and Accumulation by Higher Plants: A Literature Review

EA-5817 Final Report (RP2377-6); $25
Contractor: University of California at Riverside
EPRI Project Manager: I. Murarka

Effects of Food and Water Quality on Culturing and Toxicity Testing of *Ceriodaphnia dubia*

EA-5820 Final Report (RP2368-2); $40
Contractor: Battelle
EPRI Project Manager: J. Mattice

NUCLEAR POWER

Guidelines for Preparing Specifications for Nuclear Power Plants (NCIG-04)

NP-5638 Final Report (RP2859-5, -6, -7); $1000
Contractors: Bechtel Western Power Corp., Ebasco Services, Inc., Stone and Webster Engineering Corp.
EPRI Project Manager: W. Bilanin

Guidelines for Piping System Reconciliation (NCIG-05, Rev. 1)

NP-5639 Final Report (RPQ101-5); $25
Contractor: Reedy Associates, Inc.
EPRI Project Manager: W. Bilanin

Nuclear Plant Modification and Design Control: Guidelines for Generic Problem Prevention (NCIG-06), Vols. 1 and 2

NP-5640 Final Report (RPQ101-6); Vol. 1 and Vol. 2, $2000
Contractor: Cygna Energy Services
EPRI Project Manager: W. Bilanin

The Practical Application of Probabilistic Risk Assessment

NP-5664 Final Report (RP2682); $32.50
Contractor: IT–Delian Corp.
EPRI Project Managers: J. Gaertner, I. Wall

Below Regulatory Concern Owners Group: Evaluation of Candidate Waste Streams

NP-5670 Final Report (RPB101-26); $1000
Contractor: Analytical Resources, Inc.
EPRI Project Manager: P. Robinson

Below Regulatory Concern Owners Group: Radionuclide Prioritization Study

NP-5671 Final Report (RPB101-9); $1000
Contractor: Science Applications International Corp.
EPRI Project Manager: P. Robinson

Below Regulatory Concern Owners Group: Selection of Plants for Sampling Program

NP-5672 Final Report (RPB101-10); $1000
Contractor: Vance & Associates
EPRI Project Manager: P. Robinson

An Evaluation of Alternative Power Plant Alarm Presentations, Vols. 1 and 2

NP-5693P Proprietary Report (RP2011-2); Vol. 1 and Vol. 2, $15,000
Contractor: MPR Associates, Inc.
EPRI Project Manager: J. O'Brien

Condensation Inside Tubes

NP-5700 Final Report (RP1160-3); $32.50
Contractor: University of California at Berkeley
EPRI Project Manager: J. Kim

On-Line Vibration Monitoring for Submerged Vertical Shaft Pumps

NP-5704M Final Report (RP2338-1); $40
NP-5704SP Final Report; $25,000
Contractor: Mechanical Technology Inc.
EPRI Project Manager: J. Weiss

Determination of Thermodynamic Data for Modeling Corrosion, Vol. 1: Sulfates

NP-5708 Final Report (RP2160-2); $32.50
Contractor: Brigham Young University
EPRI Project Managers: J. Paine, M. Angwin

Handbook for Evaluating the Proficiency of Maintenance Personnel

NP-5710 Final Report (RP2705); $47.50
Contractor: Anacapa Sciences, Inc.
EPRI Project Manager: H. Parris

Oxide-Film Compositions and Morphology on Alloy 600 Tubes From Steam Generators

NP-5712 Final Report (RPS302-25); $25
Contractor: Rockwell International Corp.
EPRI Project Manager: C. Shoemaker

Human Factors Primer for Nuclear Utility Managers

NP-5714 Final Report (RP1637-5); $32.50
Contractor: Essex Corp.
EPRI Project Manager: H. Parris

Investigation of Large Bows in Reused BWR Fuel Channels

NP-5718P Final Report (RP1943-2); $5000
Contractor: Dominion Engineering, Inc.
EPRI Project Managers: D. Franklin, J. Santucci

Reactor Emergency Action Level Monitor Expert-System Prototype: Independent Review, Vol. 3

NP-5719 Final Report (RP2582-6); $25
Contractor: Science Applications International Corp.
EPRI Project Manager: J. Naser

DA/DN: A Computer Program for Pipe Fatigue Crack Growth

NP-5720 Final Report (RP1757-44); $25
Contractor: Robert L. Cloud & Associates, Inc.
EPRI Project Manager: D. Norris

HICCUP: A Computer Code for Hydrogen Injection, Combustion, and Cooldown, Using Phenomenological Models

NP-5721-CCM Computer Code Manual (RP1932-10); $32.50
Contractor: Factory Mutual Research Corp.
EPRI Project Managers: L. Thompson, J. Haugh

Chemical Decontamination of BWR Fuel and Core Materials

NP-5722 Final Report (RP2296-10, -11); $32.50
Contractors: LN Technologies Corp.; Commonwealth Edison Co.; Chem-Nuclear Systems, Inc.
EPRI Project Manager: H. Ocken

Corrosion-Product Filtration in PWRs

NP-5727 Topical Report (RP1571-4); $25
Contractor: Atomic Energy of Canada Limited Research Co.
EPRI Project Manager: T. Passell

Verification of the ATHOS3 Code Against Feedring and Preheat Steam Generator Test Data

NP-5728 Final Report (RP1066-10); $62.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: G. Srikantiah

Pressure Vessel Neutron Dosimetry at Three PWRs

NP-5733 Final Report (RP772-4); $32.50
Contractor: University of Arkansas
EPRI Project Manager: T. Passell

Loose-Parts Monitoring System Improvements

NP-5743 Final Report (RP2642-1); $32.50
Contractor: Science Applications International Corp.
EPRI Project Managers: G. Shugars, J. Weiss

PLANNING AND EVALUATION

Residual Fuel Oil Quality: Market Trends and Management Options, Vols. 1 and 2

P-5788 (Vol. 1) Final Report (RP2369-60); $32.50
P-5788P (Vol. 2) Final Report; $15,000
Contractor: Pace Consultants, Inc.
EPRI Project Manager: H. Mueller

Decision Analysis Applied to Utility Fuel Planning and Management: A Tutorial and Casebook

P-5832 Final Report (RP2359-10); $40
Contractor: Strategic Decisions Group
EPRI Project Manager: S. Chapel

Bridging the Gap Between Intuition and Analysis in the Decision Process: A Guidebook to Para-analytic Techniques

P-5839 Final Report (RP2807-3); $40
Contractor: Aretê Consulting Group
EPRI Project Managers: D. Geraghty, J. Platt

New Computer Software

The Electric Power Software Center (EPSC) provides a single distribution center for computer programs developed by EPRI. The programs are distributed under license to users. No royalties are charged to nonutility public service organizations in the United States, including government agencies, universities, and other tax-exempt organizations. Industrial organizations, including nonmember electric utilities, are required to pay royalties. EPRI member utilities, in paying their membership fees, prepay all royalties. Basic support in installing the codes is available at no charge from EPSC; however, a consulting fee may be charged for extensive support.

For more information about EPSC and licensing arrangements, EPRI member utilities, government agencies, universities, and other tax-exempt organizations should contact the Electric Power Software Center, Power Computing Co., 1930 Hi Line Drive, Dallas, Texas 75207; (214) 655-8883. Industrial organizations, including nonmember utilities, should contact EPRI's Manager of Licensing, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2866.

EGEAS: Electric Generation Expansion Analysis System
Version 3.0A (VAX)
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: Neal Balu

EGEAS: Electric Generation Expansion Analysis System
Version 3.1 (IBM, PRIME); EL-2561
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: Neal Balu

ETMSP: Extended Transient–Midterm Stability Package
Version 1.0 (IBM-XA, VAX); EL-4610, EL-2001, EL-2002, EL-2003, EL-2004
Contractor: Ontario Hydro
EPRI Project Manager: Mark Lauby

HARMFLO: Harmonic Power Flow Program
Version 4.0A (IBM PC); EL-4920
Contractor: Purdue Research Foundation
EPRI Project Manager: James Mitsche

LOADSYN: Load Modeling for Power Flow and Transient Stability Computer Studies
Version B-001 (IBM, IBM PC, PRIME VAX); EL-5003
Contractor: General Electric Co.
EPRI Project Manager: David Curtice

NORGE-B2: Linkage Between Assembly Lattice Physics Codes
Version 1-B (IBM, CDC[BE], CDC[NOS])
Contractor: S. Levy, Inc.
EPRI Project Manager: Walter Eich

CALENDAR

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

OCTOBER

4–6
FASTCHEM and FOWL: Codes for Modeling the Release, Transport, and Fate of Inorganic Chemicals in Groundwater
Washington, D.C.
Contact: Dave McIntosh (415) 855-7918

7
Trace Element Removal by Iron Coprecipitation
Washington, D.C.
Contact: Mary McLearn (415) 855-2487

11–13
Seminar: Fuel Supply
Kansas City, Missouri
Contact: Jeremy Platt (415) 855-2628

17–20
8th Annual Coal Gasification Conference
Palo Alto, California
Contact: Neville Holt (415) 855-2503

18–19
Workshop: Upgrading Low-Rank Coals
Denver, Colorado
Contact: Clark Harrison (412) 479-3503

24–26
Conference: Competitive Cost Management
New Orleans, Louisiana
Contact: Edward Altouney (415) 855-2626

25–27
Power Electronics Applications Conference and Exposition
Knoxville, Tennessee
Contact: Sue Anne Lewis (615) 675-9505

25–28
Symposium: FGD and Dry SO_2 Control
St. Louis, Missouri
Contact: Paul Radcliffe (415) 855-2720

NOVEMBER

2–4
2d International Conference on Improved Coal-Fired Power Plants
Palo Alto, California
Contact: John Bartz (415) 855-2851

3–4
Utilities and New Underground Storage Tank Regulations
New Orleans, Louisiana
Contact: Mary McLearn (415) 855-2487

15–16
9th Annual EPRI NDE Information Meeting
Charlotte, North Carolina
Contact: Soung-Nan Liu (415) 855-2480

16
Metal Chemistry and Bioavailability in Acid Water
Arlington, Virginia
Contact: Don Porcella (415) 855-2723

16–17
1988 Fuel Oil Utilization Workshop
New Orleans, Louisiana
Contact: William Rovesti (415) 855-2519

17–18
8th Reactor Physics Software Users' Group Meeting
Richmond, Virginia
Contact: Walter Eich (415) 855-2090

29–December 1
Conference: Fossil Fuel Plant Inspection
San Antonio, Texas
Contact: Stephen Gehl (415) 855-2770

29–December 1
7th Symposium: Expanding the Role of Forecasting in Utility Planning
Atlanta, Georgia
Contact: Ray Squitieri (415) 855-2630

DECEMBER

5–7
Information and Automation Technology for Serving Electric Utility Customers in the 1990s
Scottsdale, Arizona
Contact: Veronika Rabl (415) 855-2401

7–9
Resolution of Seismic Issues in Low-Seismicity Regions
Orlando, Florida
Contact: Carl Stepp (415) 855-2103

13–14
Competition and Assessment Methods
Washington, D.C.
Contact: Sherman Feher (415) 855-2838

MARCH

7–9
Symposium: Energy Utilization
San Francisco, California
Contact: David Rigney (415) 855-2419

7–9
Solid-Particle Erosion in Steam Turbines
New Orleans, Louisiana
Contact: Tom McCloskey (415) 855-2655

Authors and Articles


Armor


Divakaruni


Leyse


Scheibel


Poe


Fickett


Blatt


Goldstein

Pushing Performance With On-Line Monitoring (page 4) was written by Taylor Moore, the *Journal*'s senior feature writer, with guidance from five research managers of EPRI's Coal Combustion Systems Division.

Tony Armor has headed the Fossil Plant Performance Program since it was formed early in 1985. He was previously a project manager for 6 years. Armor came to EPRI from General Electric, where he worked for 11 years, successively in steam turbine engineering and superconducting generator design. Earlier, he taught engineering and mathematics at polytechnic colleges in London.

Murthy Divakaruni is a project manager in Armor's program, particularly concerned with controls, expert systems, and simulation software. He joined the program in 1986 after four years in digital control system development for the Nuclear Power Division. Divakaruni worked for General Electric between 1976 and 1981.

Robert Leyse is another project manager in the Fossil Plant Performance Program, with special interests in heat rate analysis and plant cycling. Formerly with Gilbert Associates, he came to EPRI in 1979 and worked in the Nuclear Safety Analysis Center until 1985. Leyse was with Westinghouse between 1967 and 1977 and with General Electric before that.

John Scheibel also is a project manager in the Fossil Plant Performance Program. He came to EPRI in 1983 after six years at Combustion Engineering, where he worked for the power systems group in supercritical boiler R&D and computer-aided engineering. Still earlier he was a power plant designer with Sargent and Lundy.

Gary Poe, another project manager in Fossil Performance, leads R&D concerned with plant cycling. He joined EPRI in 1986, following 11 years in energy and environmental research management for Acurex Corp. ■

Cleaning Up With Biotechnology (page 14) was written by John Douglas, science writer, aided by **Robert Goldstein** of EPRI's Environment Division. Goldstein, a senior project manager in the Ecological Studies Program, has focused successively on aquatic systems and atmospheric deposition since he came to EPRI in 1975. He was formerly a systems ecologist at Oak Ridge National Laboratory for over five years. ■

Tom Chema: Energizing the Business of Government (page 22) highlights the work and the thinking of a public-spirited attorney who chairs the Ohio Public Utilities Commission and holds membership on EPRI's Advisory Council. The article was written by Ralph Whitaker, *Journal* feature editor. ■

The Challenge of Packaged Cogeneration (page 28) was written by John Douglas, science writer, with the cooperation of two staff members of EPRI's Energy Management and Utilization Division.

Arnold Fickett has been director of the Energy Utilization Department since October 1985, following 4 years in charge of the Advanced Conversion and Storage Department. He came to EPRI in 1974 as a project manager for fuel cell R&D, having been in electrochemical engineering and development with General Electric for 18 years.

Morton Blatt, a project manager for research in energy systems for commercial buildings, came to EPRI in 1985, having worked for seven years with Science Applications International in the development of energy-efficient HVAC equipment. Still earlier, Blatt worked for General Dynamics in cryogenic systems and heat transfer analysis. ■

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