Isolating Nuclear Waste

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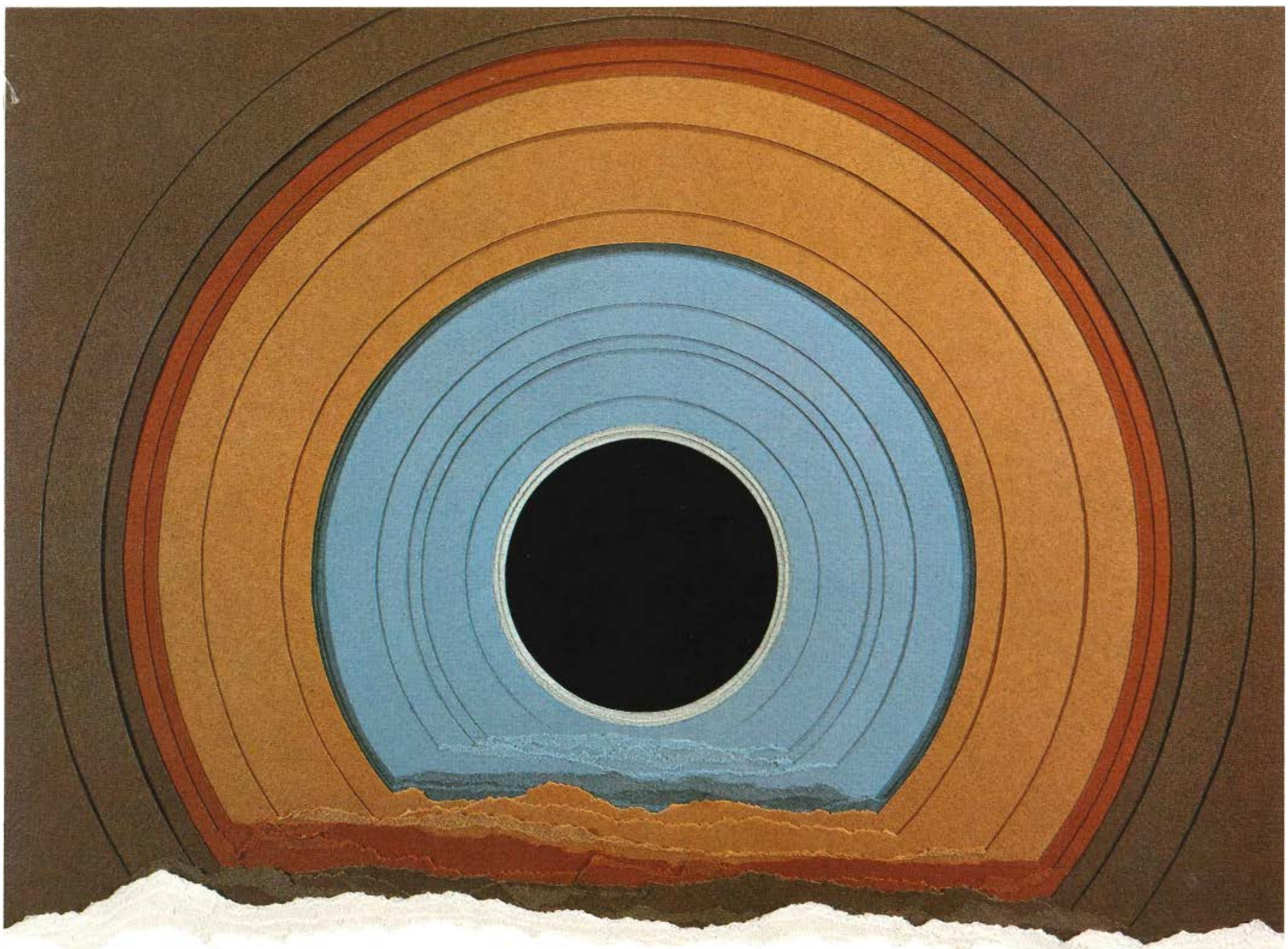

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Cover: The defense-in-depth, multiple barrier approach ensures isolation of high-level nuclear waste from the environment until significant hazard is past.

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Scheduling Waste Disposal

Public acceptance of nuclear power has been adversely biased by the perception that there are no safe methods available for disposing of radioactive waste from nuclear power production. This perception is not correct. Research work begun in 1950 in the United States and now carried on in many countries has converged on a sound technology for preparing waste for safe geologic disposal. Carefully structured evaluations of these disposal methods have led experts around the world to conclude that geologic disposal is safe. In both Sweden and Denmark, for example, studies have been completed that independently conclude their nations' nuclear wastes could be buried safely in appropriately selected geologic formations. In addition, extensive efforts in support of permanent geologic waste storage are under way in France, Germany, and Canada.

Although carefully paced waste disposal programs have been proposed for the United States since 1967, there has been no demonstration on which to base public confidence. Fortunately, there now appears to be a good chance that a waste disposal bill will be enacted by Congress this year to establish schedules and funding mechanisms for construction of a geologic repository. We hope that the program for permanent disposal of radioactive waste as proposed will proceed and that it will move at a more rapid pace than proposed. Under the current bill's provision, a demonstration repository would not be in operation before 1997, or perhaps later. We suggest that there may be justification to accelerate this project so as to ameliorate the public concern about radioactive waste by demonstrating methods of disposal that will, in our opinion, turn out to be very safe. In fact, the various pieces of the basic technology for safe disposal of solid, commercial radioactive wastes are substantially available today, as described in this month's cover story.

To accelerate the U.S. plans, a number of actions could be taken that would not compromise the safety of waste disposal.

□ Concentrate resources on identified sites in basalt and tuff. Identify a site in bedded salt, in addition to the planned Waste Isolation Pilot Plant, now scheduled for defense waste only.

□ Conduct parallel efforts in R&D, design, and licensing activities now planned for sequential action.

□ Initiate early DOE and NRC formal licensing activity.

□ Keep open the option of using the proposed test and evaluation facility site as a possible location for a full-scale repository.

By incorporating such approaches, it should be possible to accelerate the repository schedule sufficiently to achieve initial operation by the early 1990s.

To focus regulatory and licensing attention, this demonstration program, carefully controlled and monitored, will provide a basis for gaining the necessary confidence of the public in the safety of geologic disposal and do much to eliminate one of the primary barriers to the acceptance of nuclear power.

Karl Stahlkopf

Karl Stahlkopf, Director
Systems and Materials Department
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Authors and Articles

Nuclear waste is in and out of the daily news on a regular basis. Public opinion polls show that the American public is very concerned about the safe storage of nuclear waste and believes that development of permanent disposal methods is an important national priority. **Geologic Disposal of Nuclear Waste** (page 6) reviews the U.S. program today—its technology and its methodical progress as monitored by EPRI on behalf of electric utilities. The article draws on the experience and observations of three staff members of the Systems and Materials Department of EPRI's Nuclear Power Division.

Karl Stahlkopf, department director since June 1980, came to EPRI in November 1973 to manage research in pressure boundary technology; his additional responsibilities now include turbine reliability, water and steam chemistry, nuclear fuel, and nuclear waste. Stahlkopf's earlier work includes seven years in the navy, where he specialized in nuclear submarine propulsion and spent a year on the staff of the Chief of Naval Operations. He holds MS and PhD degrees in nuclear engineering from the University of California at Berkeley.

Robert Williams, manager of the external fuel cycle subprogram, has focused on nuclear waste disposal, reprocessing, and safeguards during most of his seven years with EPRI. Before that he was with General Electric Co. for six years in advanced BWR engineering and for four years in nuclear business planning. Williams is a 1961 chemical engineering graduate of Stanford University. He also completed General Electric's advanced engineering program and earned an MBA at the University of Santa Clara.

Arthur Carson, now retired, joined EPRI in June 1979 and managed external fuel cycle research between June 1980 and December 1981 while Williams held other research responsibilities. Carson was previously with General Electric for more than 32 years, including 9 years in development and construction of a nuclear fuel reprocessing plant at Morris, Illinois, and 4 years as a company consultant in waste management. Carson spent 19 earlier years in various assignments at General Electric's corporate R&D center and at the AEC Hanford Works in Washington.

■

Spreading out daily electricity demand makes more consistent use of power plants. That is the business of load management, and for many utilities today it may prove to be cheaper than building new plants to serve what is mainly a growth in peak demand.

The Load Management Decision (page 14) explains how this is accomplished as Nadine Lihach, the *Journal's* senior feature writer, describes combinations of control, incentive, and conservation utilities are using to influence their customers' distribution of electricity demand.

For the economic and technologic implications of load management, Lihach turned to Pradeep Gupta of EPRI's Energy Analysis and Environment Division. Gupta was named director of the Energy Analysis Department in January 1982, having been manager of the Demand and Conservation Program since he came to EPRI in 1980. He was formerly with Southern California Edison Co. for eight years, successively as a planning analyst, supervisor of system forecasts, and supervisor of load management planning. For three earlier years, Gupta was with Systems Control, Inc., as a research engineer. He holds three electrical engineering degrees, a BS from the Indian Institute of Technology, and an MS and a PhD from Purdue University.

■

Technologic competition between Japan and the United States in coal-fired power generation is well under way, according to EPRI's Kurt Yeager. **Japanese Challenge in Coal Combustion Technology** (page 20), by science writer William Nesbit, reports the facts and their implications for Yeager after a recent visit to Japan and a review of the R&D conducted there under the direction of the Central Research Institute of the Electric Power Industry.

Yeager, director of the Coal Combustion Systems Division since October 1979, came to EPRI in October 1974 to manage combustion and environmental control research. For the two preceding years he had been director of R&D planning for the EPA Office of Research. From 1968 to 1972 Yeager was with Mitre Corp., where he became associate head of environmental systems research. He is a chemistry graduate of Kenyon College and earned an MS at the University of California at Berkeley.

Yeager

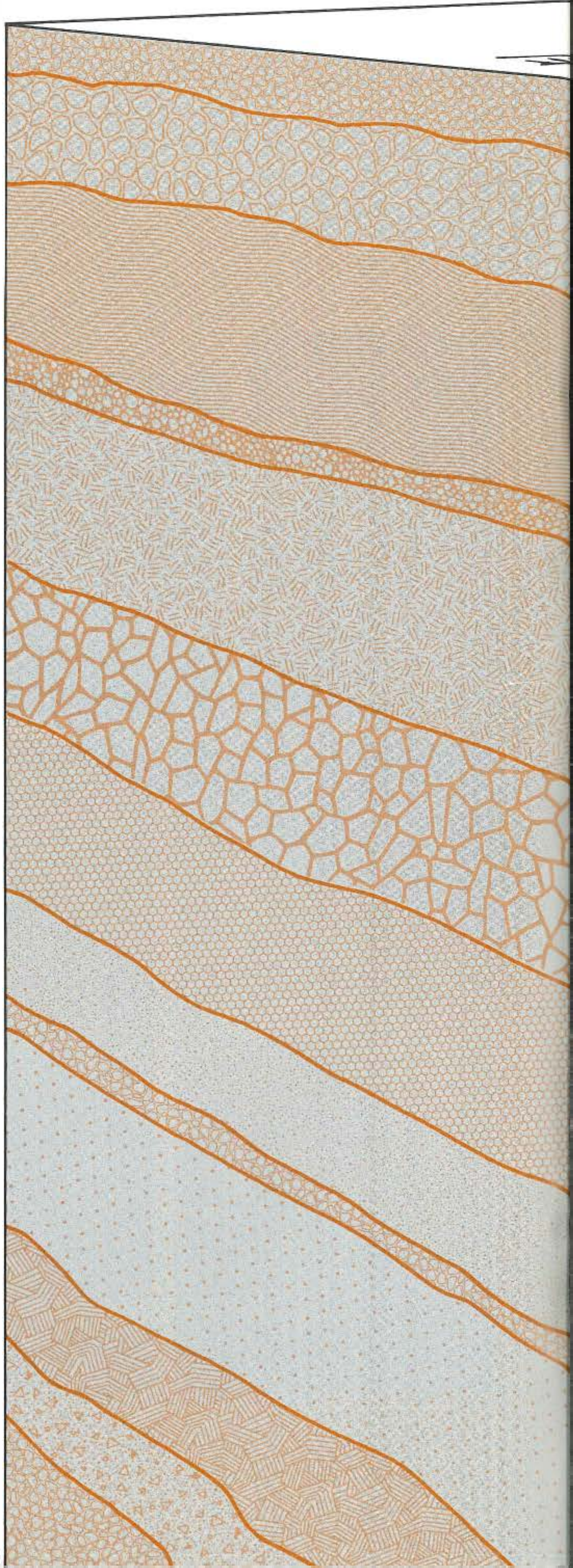
Gupta

Carson

Williams

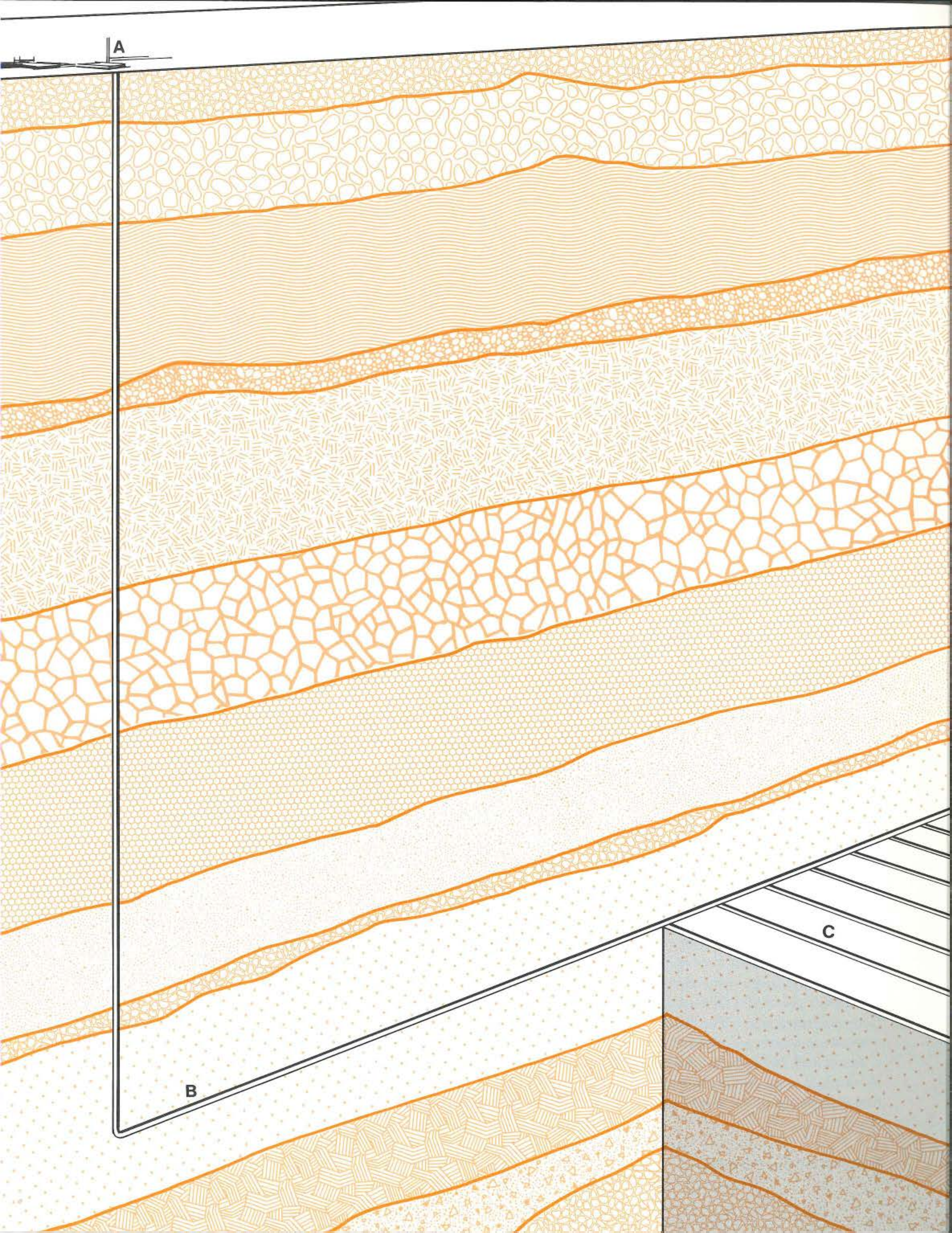
Stahlkopf

Located some 2000 ft below the surface of a carefully selected site, a repository would be mined from a host rock far below the water table, with suitable and predictable thermal behavior and chemical characteristics and no evidence of seismic activity in recent geologic history. At the surface plant **(A)**, waste is received and prepared and then lowered to the subsurface area. The waste package is moved through the main service shaft **(B)** to one of the waste disposal corridors **(C)**, where it is lowered into a waste emplacement hole in the floor. The hole is sealed and the corridor carefully backfilled. Eventually the entire 2000-acre subsurface area and the entry shaft are sealed and filled to prevent the movement of water.



Underground repositories are the likely choice for most countries seeking permanent disposal of high-level nuclear waste. These installations rely on the redundant safety of a series of engineered and natural barriers.

GEOLOGIC DISPOSAL OF NUCLEAR WASTE


A
B
C

Disposing of radioactive nuclear waste safely and permanently is the final step in closing the nuclear fuel cycle. It will also be a critical factor in determining public acceptance of nuclear power for the nation's still-growing energy needs. Aware of its implications, advocates and adversaries of nuclear power continue to debate the disposal step: How hazardous is the waste? What is required to manage it safely? Where can it be placed to keep the environment safe from its potential hazard now and in the future?

A review of current technology can help place these questions in perspective and provide a basis for understanding federal plans to proceed with permanent disposal of U.S. nuclear waste in isolated underground repositories.

What is nuclear waste?

Nuclear waste is any process by-product that has significant radioactivity and no beneficial uses. Industry, defense, medicine, and research activities of many kinds generate radioactive wastes, all requiring proper control.

Of principal concern today are the highly radioactive fuel by-products formed by commercial power reactors. The fresh fuel that is loaded into a reactor consists of uranium ceramic rods contained in corrosion-resistant metal cladding. During reactor operation, waste by-products are formed when a neutron strikes a uranium atom, splitting it into two lighter pieces. These fission fragments in the spent fuel are a mix of elements and have a predictable range of radioactive decay characteristics.

In today's power reactors, about 25% of the fuel must be replaced each year to sustain useful rates of heat release. When discharged, over 96% of the nuclear material in the spent fuel is reusable uranium or plutonium. Plutonium—an element formed when ^{238}U absorbs a neutron—is useful as a nuclear fuel.

About 3.5% of the discharged material by weight is waste, mostly radioactive fission products, plus a very small portion of unusable irradiation products with atomic weights higher than uranium. These high atomic weight irradiation products are called transuranium elements. They are of concern because their radioactivity is very long-lived, although they emit much less penetrating radiation than the fission product wastes.

Eventually, all these radioactive waste elements decay into stable, nonradioactive elements. The rate of decay and the potential hazards from the attendant radiation vary with the element. After spent fuel is discharged from a power reactor, it is stored in water-filled basins at the reactor site to permit the shorter-lived radioactive material to decay away. A year or so later, the total radioactivity level in the fuel is only about 12% of that discharged; after five years, it is down to about 3% of the discharge level. The total activity of the fuel continues to slowly decay with time from discharge.

As long as the radioactive wastes are contained within sealed fuel rods and are shielded by water or concrete, they are not a risk to public health and safety. The fuel cladding, fuel pellets (in an insoluble form), and protective barriers in the fuel storage basin ensure that hazardous amounts of radioactive material will not escape. However, the spent fuel still contains plutonium and unfissioned uranium that can be used for additional power production. (The value of the spent uranium is conservatively estimated at $150 million a year in the United States—fuel that could displace about 175 million barrels of oil annually.) To get at this valuable fuel source requires the recovery of these elements from the spent fuel by chemical reprocessing. Commercial fuel reprocessing has been delayed in the United States by government policy and uncertainty about costs, but France, the United Kingdom, and Japan reprocess routinely. The U.S. military has been reprocessing fuel to recover plutonium and recycling uranium for enrichment plant feed since 1944.

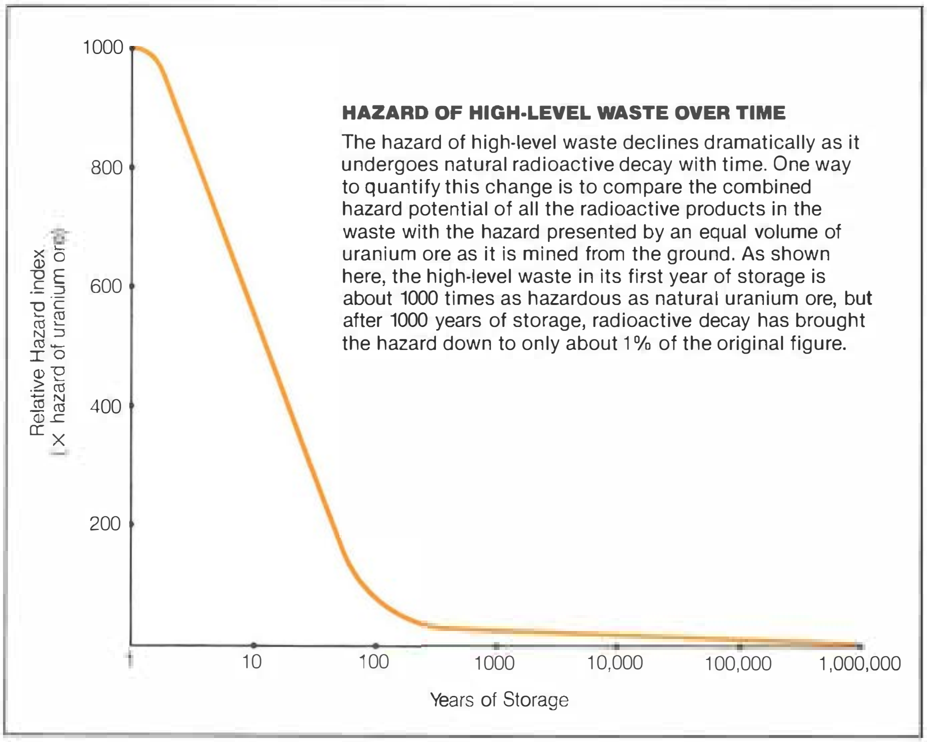
When ready for reprocessing after a year or two of storage in water-filled basins, spent rods are taken from nuclear power stations to the reprocessing plant, where the necessary chemical separations are made from remote stations behind concrete shields 6–8 ft thick. The fuel rods are chopped by a remotely operated shear into short lengths from which the fuel is then dissolved out of the metal cladding by hot nitric acid. Metal cladding hulls and spacers remain undissolved and are removed as waste.

The dissolved fuel solution is next filtered, sampled, and chemically adjusted. Then an immiscible organic solvent is introduced to extract the valuable uranium and plutonium from the solution; over 99.9% of the radioactive fission products are left behind as waste in the nitric acid solution. The organic solvent is treated to remove the uranium and plutonium and to separate them from each other. Meanwhile, the radioactive waste solution, called high-level liquid waste, must now be safely disposed of. Present plans call for the waste to be solidified into a glass for ultimate disposal ("Secure Storage of Radioactive Waste," *EPRI Journal*, July/August 1976, pp. 6–14).

Discharged fuel from a year of operating a 1000-MW (e) LWR power station (enough electricity for about 750,000 households) will contain about one ton of nuclear waste materials. When solidified into glass, this quantity of high-level waste could be formed into three waste-glass cylinders 2 ft in diameter and 10 ft long. All the waste from the discharged power reactor fuel now in interim storage in the United States, when processed, could be formed into about 900 such waste cylinders. Today's level of nuclear power generation in the United States would generate about 200 cylinders of high-level waste a year.

Management strategies

The goal of nuclear waste management is to protect people and their environment from the hazards of radioactive waste. Scientists have developed indexes to measure the hazard presented by



HAZARD OF HIGH-LEVEL WASTE OVER TIME

The hazard of high-level waste declines dramatically as it undergoes natural radioactive decay with time. One way to quantify this change is to compare the combined hazard potential of all the radioactive products in the waste with the hazard presented by an equal volume of uranium ore as it is mined from the ground. As shown here, the high-level waste in its first year of storage is about 1000 times as hazardous as natural uranium ore, but after 1000 years of storage, radioactive decay has brought the hazard down to only about 1% of the original figure.

radioactive waste products from power plants. Such indexes show that the hazard of the various radioactive waste products falls off exponentially as decay proceeds. After a thousand years or so, the combined hazard potential of the high-level waste is about a factor of 10 of an equivalent volume of natural uranium ore.

In general, several methods can be used for the safe handling and disposal of any hazardous material. It can be diluted to concentrations that have no significant effect, provided there are no readily available mechanisms for reconcentration, or it can be treated and isolated from significant contact under all credible conditions. Dilution is a safe and effective way to dispose of some radioactive wastes that exist in very small quantities. However, because of the great dilution required for safe release of highly radioactive material, this approach is unacceptable for high-level radioactive waste materials.

Isolation is the method of choice. The waste is placed in a remote location where there are no obvious migration pathways for release (even under accident conditions) and separated by multiple barriers from the living environment. The waste is isolated until it has had time to decay in terms of its potential for causing harm. Remote placement that lacks release pathways and is further protected by additional natural barriers to migration or release can ensure safety for as long as significant hazard exists.

Isolation and disposal systems

The basic parts of a safe disposal system are the site itself, the repository facilities located there, the waste package, and the waste form within the package. The repository site must be more than just remote. It must also have the kind of geologic and hydrologic characteristics that provide natural barriers to water or waste movement. And in practical terms, the site must contain a host rock formation large enough to permit full installation of a mined repository within its confines.

The site should have a low water content and low rates of water movement, predictable thermal behavior and chemical characteristics, and long-term geologic stability. The site must be in an area where there has not been a long history of flooding, earthquakes, or volcanic activity and where analysis of present conditions show a very low potential for such events in the future. Institutional and public acceptance issues also must be considered and resolved before specific sites can be developed.

As currently envisioned, the repository itself will consist of a surface plant, a subsurface mine area, and shafts for access and ventilation to the subsurface mines. The design, construction, and operation of the repository must not disrupt the natural containment and isolation capabilities of the geologic formation. At the surface plant, the waste will be received, prepared for emplacement, and transferred to the subsurface via mine shafts.

The subsurface mine area in a full-scale repository will likely occupy about 2000 acres. At the bottom of one of the shafts will be a waste-receiving area. Main access corridors will run from the receiving area to waste disposal rooms, which will be separated from one another by solid walls about 70 ft thick, depending on the type and characteristics of the rock. Waste emplacement holes will be located in the floor of each room, arranged to provide a heat distribution that will not harm the rock. The subsurface facility can be built by conventional mining.

Both the exploratory boreholes and the repository access shafts will later be sealed to prevent movement of water. While the repository is being filled with waste, controls like fences and guards will prevent human intrusion. When the repository is filled and closed, permanent markers on the surface will warn against intrusion. If underground salt formations are used, the rooms can be refilled with salt after waste emplacement. The salt will recrystallize to form

The multiple barrier concept provides defense-in-depth against the penetration of groundwater, the primary safety concern. With today's technology, the waste package could remain unbreached for hundreds of thousands, if not millions, of years.

(1) Geology provides the major barrier. The host rock shows essentially no water movement and is geologically stable. Candidates include granite, basalt, tuff, and salt.

(2) Backfill of crushed rock to facilitate heat transfer from the waste package and to ensure the integrity of the host rock.

(3) Backfill of bentonite and basalt to retard the penetration of water and to act as an ion-exchange material to absorb radionuclides and delay their migration.

(4) Metal or ceramic corrosion barrier.

(5) Overpack of cast steel for radiation shielding and physical durability. This allows on-site rather than remote handling of the contained waste and reduces the radiolytic effects on groundwater.

(6) Cannister of corrosion-resistant steel.

(7) Waste converted to nonleachable solid, such as borosilicate glasses, synrock, or tailored ceramics. In the presence of water, the leach rate of vitrified glass is approximately 1 part per 100,000 per year.

a bed similar to the one that existed before mining.

The design of the waste package placed within the repository is a vital part of the overall system. It must allow for safe handling and emplacement operations and possible near-term retrieval of the waste, should that be necessary. For about the first 1000 years or more, depending on emplacement practice, the waste packaging can isolate the waste from its surroundings. A waste package consists of a cannister, overpack sleeve, and backfill barriers.

The waste cannister will protect workers during interim storage, transportation, handling, emplacement, and any later retrieval operations. The cannister material must be able to withstand corrosion attack from subsurface water. The cannister will be designed mainly for chemical durability, with less emphasis on impact strength and other properties important to safe handling and transport.

A primary purpose of the overpack is to provide shielding to reduce the radiation dose rate at the container surface. This could permit handling in the repository with relatively conventional equipment and reduces possible radiolytic effects on groundwater that might penetrate the repository after closure.

Backfill materials are also important. They can stop the movement of intruding groundwater; modify groundwater chemistry to reduce corrosiveness; shift with any rock movement to prevent undue stress on the waste package; and provide effective heat transfer to help control package temperatures. In the event that water ever reaches the waste, the backfill materials can absorb radioisotopes from the contaminated water and thus significantly delay their migration to the surface or its waters. Several layers of backfill can be used with different materials designed for particular functions. These layers would be effective barriers to migration and would be added as extra measures of protection.

The actual waste form at disposal must be stable at the temperature and radiation conditions to which it will be exposed in a repository. Stability is needed so the waste will not degrade the package from within. Maximum resistance to water leaching is important to provide protection in the unlikely event that the barriers to water entry are penetrated.

A major consideration in evaluating a waste form is processibility—the ease with which high-level liquid waste can be converted to the proper leach-resistant solid form for disposal. This conversion process must be feasible in a remote and heavily shielded (about 8 ft of concrete) site, and comply with personnel and environmental standards. Many different waste forms are known to have good stability and leach-resistance characteristics. The processibility of at least one form, borosilicate glass, has been well established. In Canada a highly resistant, fixed waste form, in effect a synthetic garnet, has been exposed to leaching conditions (experimental) for over 25 years with good results.

System performance

Predictions of the waste disposal system's performance rest on knowledge of its individual parts and how they function together. For example, a range of host rock types are known to have suitable physical and chemical characteristics. How to select an actual repository site and gain public acceptance for the site have not been demonstrated, but there are many locations that are geologically stable, contain very little water, and would inhibit any water movement through the rock.

Demonstrations have already shown how to excavate the repository in rock, install facilities, emplace packaged waste, and ensure that the mined area is essentially dry when backfilled and sealed. Conservative analyses for the purpose of licensing generally assume that the backfill would immediately resaturate from groundwater, but actual times for this phenomenon to occur can range from hundreds to thousands of years, depending on the rock type, and in most practical cases would never occur because wastes would be buried far below the surface water tables. There are backfill materials that can greatly retard water seepage and reduce its corrosiveness. Beyond this, engineered barriers are designed to stop water from reaching the waste, thus providing additional protection. The corrosion-resistant materials for use in overpack and cannisters are further barriers to the penetration of water.

NRC regulations, now drafted but not yet approved, call for the waste package to fully contain the waste material for at least 1000 years. Use of the barriers described above should give this minimum containment capability. The contribution of package integrity to the overall system needs to be analyzed to see if more or less elaborate provisions are required.

Some producible waste forms have shown better leach resistance than others. A high leach resistance ensures that the release of radioactive constituents, if they were ever to contact water, would be extremely slow. Leach resistance contributes to safety by retarding release of the waste material for thousands of years.

The next logical step is to confirm these expectations about system performance with carefully monitored tests performed under field conditions.

Recent progress on waste disposal

Substantial progress has occurred recently in moving the waste disposal program from the laboratory to the field. Site explorations for civilian waste disposal are under way at DOE's Nevada Test Site and at the basalt waste isolation pilot plant on the Hanford Reservation near Richland, Washington. Military waste disposal is being investigated at the waste isolation pilot plant near Carlsbad, New Mexico, where the first of two exploratory shafts was completed during the fall of 1981.

Eleven prototype cannisters have been emplaced in the Climax mine at the Nevada Test Site to obtain more data about the impact of the waste on the repository environment. The cannisters contain spent fuel, which is a good substitute for vitrified high-level waste in testing for thermal effects, radiation effects, and rock mechanics.

Moreover, extensive site-screening programs are nearly complete. These will name potentially acceptable regional sites in the Midwest, Northeast, and Southeast for a system of regional repositories. Also speeding the program along is the satisfaction of several important procedural requirements. The final generic environmental impact statement for commercial high-level waste was submitted to EPA and mined geologic repositories were then adopted as the preferred location for high-level waste disposal. This document, which took over three years to complete, was subjected to extensive public scrutiny and comment and now stands as a legal milestone in the federal program for high-level waste disposal.

Meanwhile, scientific findings continue to accumulate on all the technologies of high-level waste disposal. This new knowledge has confirmed and refined understanding of the mechanisms for waste-form corrosion and leaching, the long-term behavior of engineered barrier materials, analytic model development, and the geology of specific sites.

Institutional roadblocks are also being cleared. Lengthy dialogue has occurred between the DOE program representatives and officials in states with possible candidate sites. The idea of regional repositories has been discussed with the states, the Congress, and the public. A consensus is developing over ways to balance state interests with regional and national interests, as indicated in Senate Bill 1662, now pending in the 97th Congress. The 1980 National Low-Level Waste Policy Act (PL96-573) allows regional compacts for low-level waste disposal and opens the door for high-level waste disposal siting.

International solution to waste disposal

In France, where commercial reprocessing of fuel has gone on for several years, waste disposal is advanced. In 1978 the French began operating a full-scale waste vitrification plant, where the waste is chemically bonded into glass. They now have the fission products from

At the Climax Mine at the DOE's Nevada Test Site, 1400 feet below the surface, 11 spent fuel bundles have been buried to permit measurement of thermal and radiation effects of waste disposal in granite. This facility is the first demonstration of emplacement of significant quantities of spent fuel in a geologic media in the United States. Results from the demonstration will be helpful in designing permanent disposal facilities for vitrified high-level waste.

5500 t of reactor fuel stored in borosilicate glass in the air-cooled vault at Marcoule. The French are investigating salt, granite, and clay for geologic disposal and, meanwhile, are using surface storage and cooling of the waste to reduce the thermal effects after final emplacement.

In Sweden the KBS project, begun in 1976 and completed in 1980, developed a conservative design for spent fuel and high-level waste disposal in granite. The KBS design was reviewed and found acceptable by panels of Swedish, international, and U.S. waste disposal experts. The KBS study was ordered by the Swedish Parliament, concerned about whether to continue operation of six reactors and finish building six more. The study found that the nation's nuclear waste could be safely buried, and a subsequent national referendum approved the continued operation of Sweden's reactors for their useful lifetime, through 2010.

The neighboring Danish government has ordered a full investigation of nuclear waste disposal capability before any commitment to commercial nuclear power. The study, begun in 1977, examined the feasibility of waste disposal in salt domes in Denmark, both in mines and in deep drill holes. The utilities conducting the study found the results confirmed that safe disposal of high-level waste was also feasible in Denmark. The results have been submitted to Danish regulatory authorities for review.

In Great Britain processing of fuel from commercial reactors began in 1964 at the Windscale facility. The liquid high-level waste has been stored in carefully monitored stainless steel tanks while waste solidification processes are being developed. A pilot plant to demonstrate the British-developed Harvest process will start up in 1982. A full-scale facility for vitrification of the Windscale high-level waste is planned to go into operation in 1987.

In Japan the processing of LWR fuel began at the Tokai Mura reprocessing plant in 1978. By May 1981 over 100 t had been processed, with the waste stored in carefully monitored stainless steel tanks. A prototype of the waste vitrification equipment is scheduled to go into operation in 1982, and the Tokai Mura high-level waste solidification pilot plant is scheduled to start up in 1987. The pilot plant will solidify the accumulated waste inventory, as well as the waste from the 200-t/yr reprocessing plant.

In the Federal Republic of Germany an extensive fuel cycle program exists to support commercial nuclear power development. Approximately 100 t of spent fuel have been processed in the Wiederaufarbeitung Karlsruhe (Wak) pilot plant, which started operations in 1971. A pilot-scale vitrification plant, Hochaktiv Verglasungs Anlage (Hova), is planned to start up at the Karlsruhe site in 1986 to vitrify the waste stored there. The Germans have conducted extensive tests in support of waste disposal in salt at the Asse mine and are conducting R&D on waste disposal in hard rock at the Konrad mine near Wolfenbüttel. The construction of a fuel cycle center and associate waste repository at Gorleben of sufficient size to serve the entire German nuclear industry has been deferred until 1985 while an alternative approach of preparing smaller regional facilities is studied.

Current U.S. schedule

The current DOE schedule for a waste repository calls for completion of site characterization and qualification at three locations by 1985; submission of a preliminary safety analysis report in 1988; operation of a test and evaluation facility in 1989; NRC review culminating in a construction permit by 1991; construction and operation of the waste repository in 1997. A longer schedule has also been proposed that permits a three-year experimental program of tests and measurements at each preliminary site and results in repository operation in 2006.

One part of the present DOE program, the test and evaluation (T&E) facility, may permit a demonstration of waste disposal on a significant scale by 1989. In today's plans, a T&E facility would be located at one of the sites now characterized, with completion of plant design in 1987 and construction in 1989. Handling procedures for several hundred cannisters of waste per year would be tested at the facility. Other tests and characterization of the rock and geology at the T&E facility site would also be conducted.

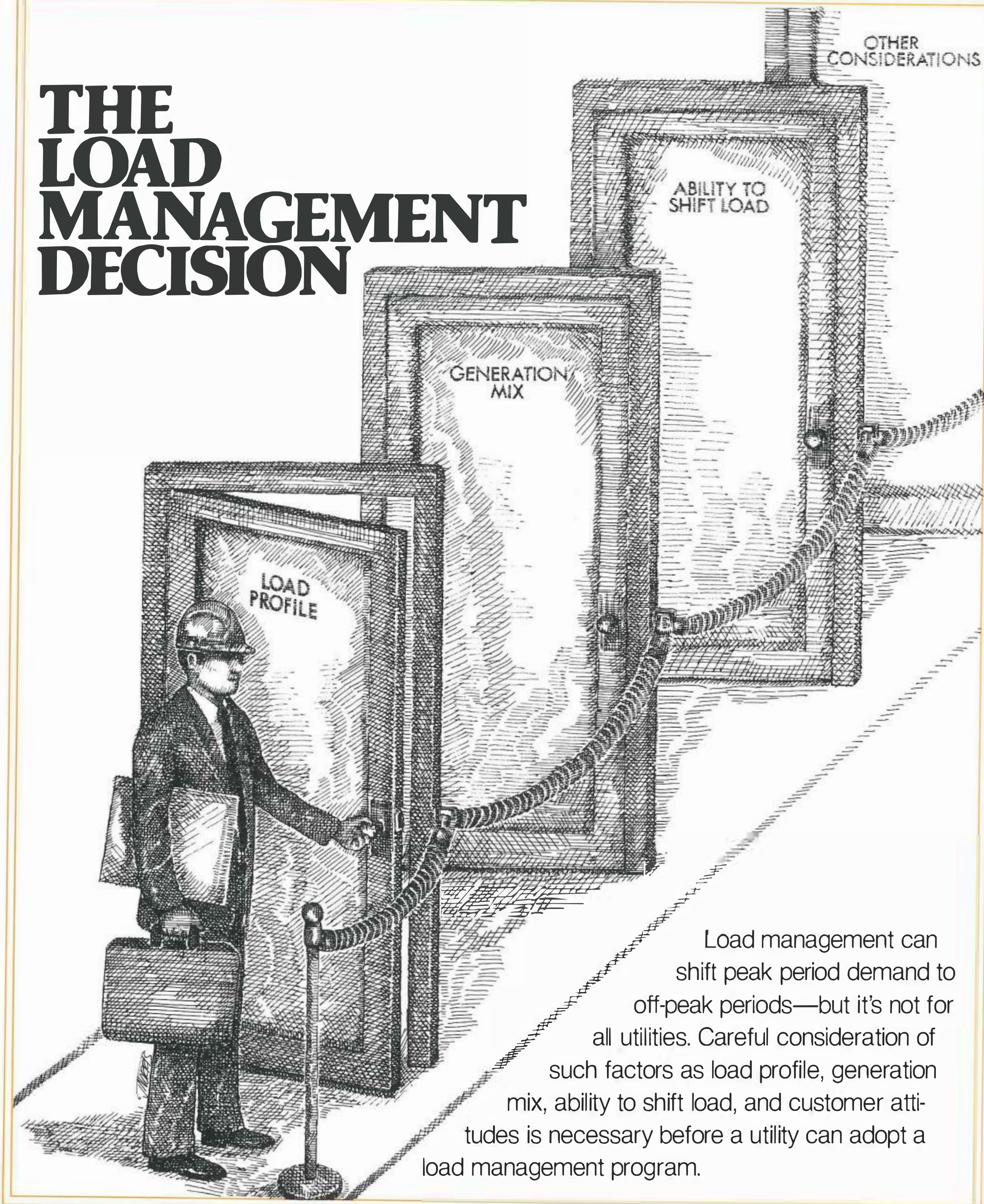
However, there is still some uncertainty about the siting and licensing ground rules for such a facility in the United States. Under current plans the facility would be built for demonstration, with all waste emplaced on a retrievable basis while more testing goes on. It has been proposed that such a facility be unlicensed, or if licensed, that it be by an expedited process.

Critics say that if the T&E facility is to be built without a formal licensing action, it should not be used as a future commercial waste repository. Proponents argue that a suitable site should not automatically be disqualified because it has been used for a demonstration and that using the T&E facility would help provide better data for site-specific licensing. The licensing and siting ground rules for this facility currently rest in the hands of the 97th Congress, with action expected sometime in 1982.

Efforts now in progress in laboratory, field, and legislature are helping resolve the remaining questions about how to carry out an effective national waste disposal program. If the proposed federal T&E facility can indeed provide a significant demonstration of waste disposal technology before the decade is out, then the nation may well look forward to having its first high-level nuclear wastes safely and permanently buried by the century's end. ■

This article was written by Karl Stahlkopf, Robert Williams, and A. B. Carson of the Nuclear Power Division.

THE LOAD MANAGEMENT DECISION



Load management can shift peak period demand to off-peak periods—but it's not for all utilities. Careful consideration of such factors as load profile, generation mix, ability to shift load, and customer attitudes is necessary before a utility can adopt a load management program.

People pursue daily routines, and utilities duplicate those routines when they supply electric power. When customers sleep, electricity demand declines. When they wake, demand perks up. Electricity demand follows customers faithfully through breakfast, work, and dinner, over weekends, through air-conditioned summers and electrically heated winters.

But while it takes customers only a flick of a switch to create demand, it takes far more than that for utilities to meet demand. Enough generating capacity must always be kept on hand to supply power during demand peaks, even though much of that capacity lies idle the rest of the time. To meet fluctuating electricity demand, utilities rely on three types of generating units. Baseload plants—usually coal or nuclear units—operate day and night, satisfying more or less constant electricity demands. These plants are typically the most efficient and least costly plants to run. Intermediate plants—more responsive to changes in demand but more costly to run—operate on a less-constant basis to provide power during normal bulges in the daily load profile. Peaking plants—usually the most costly of all plants to run because of their gas- or oil-fired turbines for quick startup and shutdown—are on standby for those occasions when demand surges and immediate electric backup is required for short periods, such as during the increase in air conditioning that accompanies hot weather.

The classic arrangement of baseload, intermediate, and peaking plants has long permitted utilities to meet customer electricity demand at the least cost. But customers have been changing in recent years, and electricity demand is changing with them. Air conditioning, once a luxury, has become commonplace and is responsible for the needle-sharp peaks that characterize many utilities' summer load profiles. Space- and water-heating demand has continued to grow, and many utilities' winter peaks have become sharper as a result. Utilities customarily dealt with growing peak periods by constructing new power plants, but the economics of power plant construction have been changing too.

New plant construction now costs more than ever because of soaring materials, labor, and financing costs. Plant licensing is increasingly difficult because of regulatory roadblocks. And once built, plants cost more to run, a consequence of the high cost of fuel and maintenance. More and more utilities are becoming convinced that there may be better alternatives for meeting peak demand than constructing new power plants.

Energy storage is one alternative for satisfying peak demand. Less-expensive baseload power can be stored through pumped-hydro installations. But sites for pumped-hydro are hard to find and license; newer storage systems, such as utility storage batteries and compressed-air energy storage, are still under development. For the present, one answer that appears attractive in many cases is controlling demand by load management. Under this strategy, some peak demand would be shifted to an off-peak period. A utility would thus be able to use its existing plants more of the time and defer new plant construction. In some utility systems, load management has the potential for lower capital costs and shorter installation lead times than new plant construction because there are no heavy construction expenses that can escalate sharply with every delay and no plant-licensing processes to contend with.

Load management is not a new idea; it has been used by a number of utilities for many years. But with new economic situations and new technologies, more and more utilities are venturing into load management. Most have done preliminary feasibility studies. Many have programs now in progress, such as Duke Power Co. and Southern California Edison Co. Other utilities with load management programs include Arkansas Power & Light Co.; Bonneville Power Administration; Buckeye Power, Inc.; Cobb Electric Membership Corp.; Detroit Edison Co.; Pacific Gas and Electric Co.; Salt River Project; Tennessee Valley Authority; Virginia Electric and Power Co.; and Wisconsin Electric Power Co. An annual EPRI–DOE survey shows that over 100 utilities are now involved in a variety of load management programs. Load management may not be as reassuringly familiar as a new power plant, but as Pradeep Gupta, director of EPRI's Energy Analysis Department, Energy Analysis and Environment Division, explains, it is a resource that deserves utility consideration.

Two ways to go

There are two basic approaches to load management. One is direct utility control over interruptible customer loads (such as air conditioners) to reduce peak period demand and over deferrable customer loads (such as water heaters, space-heating systems, and swimming pool pumps) to shift load to off-peak periods. The other approach is customer incentive, including time-of-day rates that reward the shift of electricity use to off-peak periods by charging less for it. Direct load control is attractive to utilities because with it they can plan for specific demand levels. Yet customers may not wish to relinquish control of certain appliances to utilities, even for the short periods of time that would be necessary. With customer incentives such as time-of-day rates, the customer controls which appliances are used, and when. Customers may opt to use nonessential appliances during off-peak periods when rates are low, or they may choose to pay the higher peak rates. However, customer incentives may not guarantee the utility a set demand level, and so the utility must maintain a higher level of backup peaking power.

Direct load control and customer incentives are being used in assorted combinations by utilities. Direct load control may be the answer for one utility; time-of-day rates may be more suitable for another. Even conservation programs, such as insulation improvements, are load management strategies in that they can help check the growth of peak demand.

APPROACHES TO LOAD MANAGEMENT

There are as many potential load management programs as there are utilities but only two basic techniques to steer customer demand to off-peak periods: direct utility control and customer incentive. Each technique has its own advantages and disadvantages. Sometimes the two approaches may be combined to produce a hybrid technique based on the best features of both approaches.

Direct Utility Control

With direct control, the utility uses switching devices to shift deferrable customer loads (e.g., water heaters) to off-peak periods or shut off interruptible loads (e.g., air conditioners) to reduce peak demand. Direct load control is attractive to utilities because they can plan for specific demand levels. However, participating customers may not wish to relinquish control of certain appliances, even for the short periods that would be necessary.

Customer Incentives

Incentives, such as time-of-day rates, encourage customers to shift electricity demand to off-peak periods, typically by charging less for off-peak electricity. The customer decides which appliances are used and when. Nonessential appliances may be used during off-peak periods when rates are low, or the customer may choose to pay higher peak rates. However, customer incentives may not guarantee the utility a definite demand level, and the utility must plan accordingly.

Hybrid Systems

With the right hybrid system, a utility could be guaranteed a set level of peak demand, while the customer could be assured the choice of how to keep within that level. Southern California Edison Co.'s patented demand subscription service is an example of a hybrid approach that gives customer and utility the benefits of both direct utility control and customer incentives.

Duke is one utility pursuing a wide range of approaches in its load management program, which was begun in 1974 to reduce the growth rate of the system peak demand. Duke had calculated that customer electricity demand would hit 18,823 MW by 1990, but because of financing difficulties, its 10-year plant construction program could be expected to provide only 16,280 MW of capacity by that date. To make up the difference, Duke decided to implement an extensive load management program. Its winter peak demand has already been reduced by over 1124 MW through this program.

Duke's effort concentrates on residential customers, who account for 74% of its long-term winter load management goals and about 53% of its summer goals. Significant features of the residential program are the residential conservation rate and energy-efficient structures programs. Customers whose homes meet a variety of tough insulation standards can get a residential conservation rate that is 16% lower than the alternative residential rate for use above 1300 kWh a month. The same residential conservation rate is offered to customers with new homes that meet Duke's stringent energy-efficient structure qualifications. Another option is a time-of-day rate with both a peak demand and an energy charge. Load control of residential central air conditioners and water heaters in exchange for a bill credit is another choice available to an increasing number of homeowners.

Duke has several load management options for industrial and commercial customers. Because factories and office complexes may have private generating equipment standing by for emergencies, Duke offers a special credit to customers who agree to use their private generating equipment to reduce peak demand. It also has an interruptible provision for industrial and commercial customers. The customers agree to make firm load reductions during emergency periods; in return, a monthly credit is applied to their bills, based on the amount of power available for interruption during peak periods.

Some innovative approaches to load management that combine the best of direct load control with the best of customer incentives are also being tried by the utility industry. Consider Southern California Edison Co., whose load management program is aimed at nipping sharp summer peaks. Along with direct load control of air conditioners and water heaters, rate incentives, and conservation, SCE has demand subscription service. Under this patented approach, SCE and participating residential customers agree on a level of electrical service based on the electrical demand the household plans to place on SCE. The customer receives a monthly credit based on this selected demand level; the lower the level, the higher the dollar credit. A radio-controlled demand-limiting device is installed on the customer's meter, and when activated by SCE during peak periods or periods of capacity shortage, it compares the actual rate of electricity use with the previously selected demand level. If the rate exceeds the selected demand level, it will automatically interrupt electrical service. The customer restores service by reducing the rate of electricity use to the selected demand level and manually resetting the demand subscription device. (If no one is home when service is disconnected, it is automatically restored at the end of the emergency period.) Through demand subscription service, the utility is guaranteed a set amount of peak demand, and customers choose how they stay within that peak demand limit.

Large customer cooperatives are another hybrid load management concept that SCE is testing. SCE contracts with a cooperative of industrial and large commercial customers for a selected demand level. The cooperative is responsible for allocating peak power priorities within its group inside demand budget limits. When SCE hits an emergency peak or capacity shortage, the members receive a computer signal from SCE telling them to shed load within 30 minutes. SCE then redirects the power to other customers, and the cooperative is compensated by a reduced electricity bill.

Finding the right program

The load management approaches that companies such as Duke and SCE are following may not work for all utilities. In fact, load management as a strategy may not work for every utility. Certain conditions are needed before load management can even be considered, according to Gupta. One condition is the "peakiness" of the utility's daily load profile. (This is technically expressed as a low daily load factor—the ratio of average demand to peak demand. Daily load factors may typically be 80%, and large savings could result from improving the load factor to 85–90%.) Obviously, a utility with a flatter load profile will not need load management because its power plants are more fully used. Forecast growth of peak demand is also a consideration; if a marked increase in peak demand is expected, load management may be indicated.

The utility's generation mix, or collection of power plants and fuels, is another condition. If a utility has a coal or nuclear baseload, but burns oil or gas to meet sharp peaks, load management could spare some of that costly oil or gas. But if a utility meets its peaks with less-costly energy, such as pumped hydro, load management may be unnecessary. If a utility burns oil and gas to meet both peak and off-peak demand, load management would provide fewer benefits because there is no inexpensive baseload energy to shift to. If a utility has new plants well under construction, load management may not be attractive.

A final condition for load management is the customers' ability to reduce peak load or shift peak load to off-peak periods. This depends partly on the saturation level of devices, such as water heaters and air conditioners, and partly on whether customers can use those devices at off-peak periods.

SCE is a tidy example of a utility whose planners could clearly see load management benefits. SCE has needle-sharp peaks caused largely by summer air conditioning loads. These peaks are met with costly oil; expansion to coal or nuclear is difficult because of air quality and seismic restrictions.

Once a utility passes the initial test for load management, its search for cost-effective programs is just beginning. An experimental load management program may be the next step. At this point, the utility must decide on which load management programs it is likely to use; the population it is likely to reach; the public education necessary to familiarize potential participants with the program; the incentives that will have to be offered to induce customers to join and to stay in the program; the equipment that will be required; and the additional staff that will be needed to handle marketing, equipment installation, complaints, and new billing and metering.

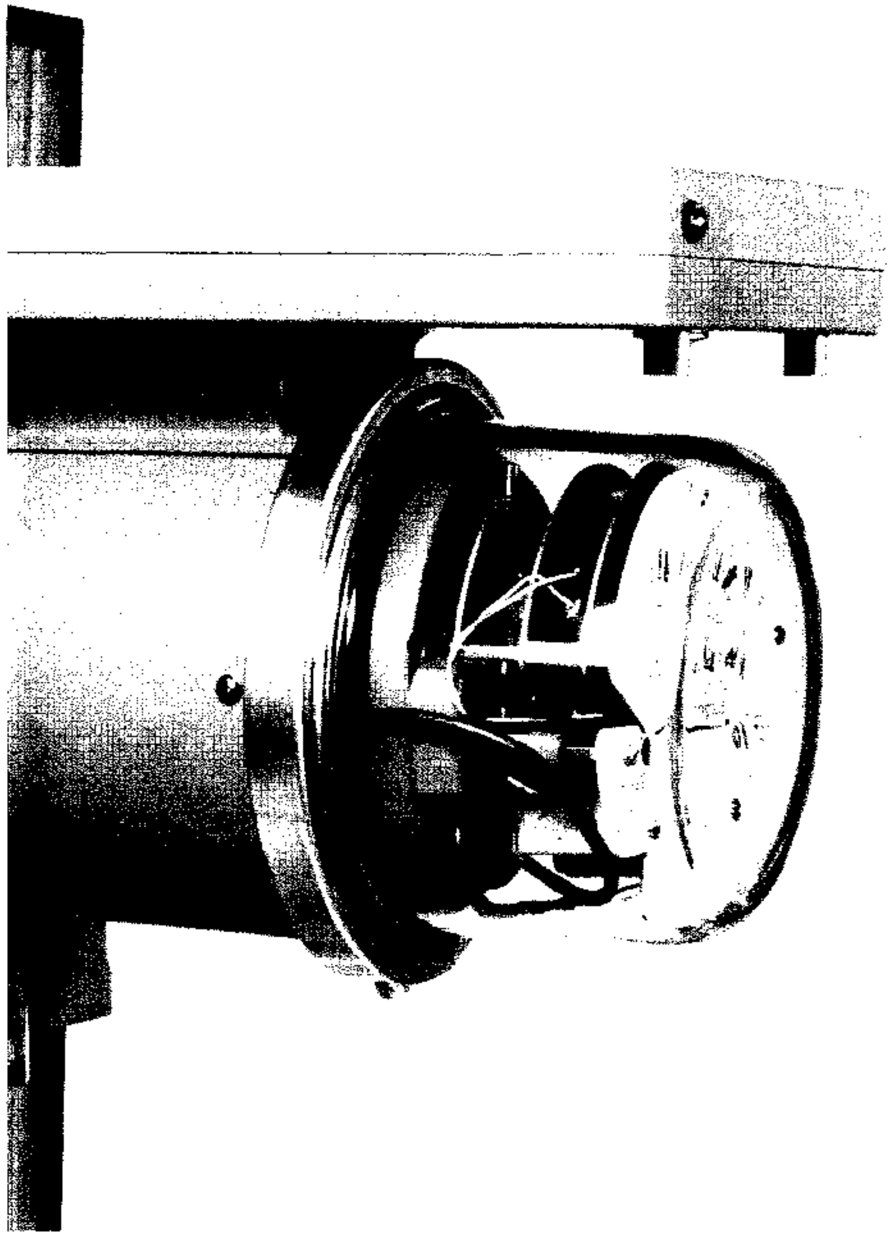
A limiting factor in load management experimentation is the time and cost required for these experiments. "An experimental program may cost anywhere from $1 million to $5 million per utility," says Gupta. EPRI–DOE's annual survey of utility load management projects shows a wide range of experiments, but because of the many differences between utilities, load management data and experiences cannot be readily compared. Customer response can vary widely, for example, depending on different lifestyles and demographics. Or load management technologies can vary in effectiveness in different areas—radio control may be ideal for flat rural areas in Kansas but impossible in the skyscraper canyons of Manhattan. Utilities would like to share load management experiences, but they need a reliable way to extrapolate results from one utility to another. EPRI's EAE Division is carrying out several projects to see how this can be done. Two studies are on load control and time-of-day rate response; a third is examining customer electricity use patterns.

When the results of load management experiments are in, the utility takes these results and performs a cost-effectiveness analysis. The utility must compare the costs and benefits of its proposed load management program with the costs and benefits of other alternatives, including new power plants or power purchases from other utility networks. Utilities have established procedures for comparing the cost-effectiveness of new power plants or new power purchases with one another. But load management is an altogether different resource. To compound the problem, reliable load management information is scanty, and complete models are lacking. EPRI's EAE Division and utilities are developing data and models to estimate the impact and cost-effectiveness of load management. These analyses must consider the effects on utilities and their customers over a long period of time, taking into account such variables as inflation rates, capital costs, and customer acceptance.

Enlisting customers

When a utility is convinced that load management is feasible and cost-effective, the next item on the agenda is how to implement it. Some utilities simply send notices of the new program to customers, explaining how they can lower their electricity bills through participation in the program. The unadorned mailings, however, have not elicited much customer interest. An EPRI survey of load control programs at 16 utilities found that minimal marketing netted a discouraging 10% customer response.

A heartier response—70%—was reported when utilities actively marketed their programs to the customers. Many utilities did, in fact, adopt that approach in recruiting customers for their load management programs. Direct personal contact, such as door-to-door interviews, was found to be the most effective way to get participation, but this direct approach also took the most manpower. Newspaper and magazine advertisements, brochures, and bill-stuffers are widely used to supplement the direct approach. Television and radio spots are also popular



DEMAND SUBSCRIPTION SERVICE

Under this patented Southern California Edison Co. approach, each participating residential customer contracts with the utility for a specific electricity demand level, based on likely demand requirements. In return, the customer receives a monthly billing credit; the lower the selected demand level, the higher the dollar credit. Meanwhile, a radio-controlled demand-limiting device is installed on the customer's meter. When activated during peak periods, a red lamp on the device lights up, and the device compares the actual rate of electricity use with the agreed-upon demand level. If the rate of electricity use exceeds the selected demand level for 60 seconds or longer, the device automatically disconnects electric service. To restore service, the customer chooses which appliances to turn off to reduce demand to the selected level, and then pushes a reset button on the device. If no one is home, electric service is automatically restored. If the customer finds the selected demand level is too low, the contract can be revised. In short, this approach gives the utility a reasonable guarantee of peak electricity demand requirements, while the customer decides how to stay within the selected electricity budget.

with utilities, including SCE's heat-wave plea to customers, "Give your appliances the afternoon off." Public speakers and information exhibits are also used.

Public education is critical to load management success, emphasizes Gupta, "The customer is the one who makes the decisions in load management. If the customer doesn't go along with it, it doesn't work." Yet utilities have found that it can take a large-scale effort to get people interested in load management. For example, SCE needed 2000 volunteer households with central air conditioning for one of its early direct load control field tests. The company had to send out almost 500,000 letters to customers announcing the upcoming experiment to get just 11,000 households interested in learning more about the test. "The whole selection process took six months," recalls Gupta. "How long would it have taken to sign up 200,000 customers?"

When customers consent to a load management program, necessary equipment must be installed. This equipment varies from program to program and includes not only control equipment on the utility system but also controls on the customers' end. Time-of-day meters are necessary for time-of-day rates. Load control switches are needed for direct load control of appliances. Special equipment is required to implement interruptible rates when large customers agree to service interruptions at certain periods in exchange for a credit on their bills. If the utility wants to do remote billing, two-way communication systems must be incorporated into control and metering systems. If such additional end-use equipment as heat pump controls or heat or cool storage devices are part of the plan, they too must be installed.

Utilities have tried a variety of approaches to equipment installation. For example, in Duke's load control program for residential water heaters and air conditioners, customers pay an installation fee for the load control device and then receive a monthly credit on their electric bill. In Duke's residential conservation rate program, utility representatives inspect homes to see if they qualify for a lower electricity rate on the basis of weatherization.

Utilities are finding out that not all the hardware needed to implement load management programs is perfect. "Most of the special meters, load control switches, and communications devices are still in developmental stages," affirms Gupta. "The overall reliability of many of these devices is lower than a utility would expect from a fully commercial product." Therefore, shakedown testing, additional maintenance, and early replacement may be in store for the utility. Also, the new equipment is expensive. Ordinary electricity meters cost \$20–\$25 each, while new meters that register time-of-use information cost \$100–\$300 each. New designs will eventually reduce these costs, but for now, utilities are often hesitant to commit themselves to a large hardware investment when waiting could bring them improved equipment at better prices.

EPRI's Electrical Systems Division is one group now researching new time-of-use meters and other load management hardware. Bidirectional communication and control equipment based on power line carrier, telephone, and radio technologies is being developed and tested in this division. These systems will be capable of customer load control, remote meter reading, and other functions. Meanwhile, EPRI's Energy Management and Utilization Division is researching customer-side load management hardware, including heat and cool storage and logic controls for such loads as lighting, air conditioning, and electric heating.

Uncertainty ahead

Many utilities are finding that their load management programs are well received and well worth the effort of program analyses, customer recruitment, and hardware installation. Duke anticipates reductions of 4769 MW in its summer peak and 5992 MW in its winter peak by 1995 (percentage drops of 21.9% and 26.4%, respectively) as a direct result of its load management program. SCE hopes that by the same year, it will have reduced its summer peak demand by 1700 MW (a 9% drop) through load management. Yet load management is still an uncertain resource. Unlike a power plant that can be counted on to run for 30 or more years, no one knows how long load management will remain effective. Studies to date document relatively short-term customer response. Should customer response slacken, there is always the unpleasant possibility that unfavorable demand patterns will reappear, and unanticipated power plants might have to be built to support that renewed demand. This could ultimately result in higher rates for the customer.

Load management is also a limited resource. While power plants can be built more or less as needed, peak load can only be shifted so much before the cost of shifting soars or before new peaks materialize. This happened in West Germany a few years ago when a large utility instituted a thermal storage program to flatten daytime heating loads. The favorable incentives of the new program encouraged widespread customer participation, and a new peak surfaced at night because of the recharging of storage heaters. Additional controls and a less favorable rate structure had to be instituted by the utility to mitigate the problem.

"There are uncertainties in load management," concedes René Malès, director of the EAE Division. "But we also face uncertainties in the construction of new plants. Utilities are just more used to those uncertainties." As information and data from ongoing studies are collected and shared, utilities will get used to and learn to deal with the uncertainties of load management. ■

This article was written by Nadine Lihach. Technical background information was provided by Pradeep Gupta, Energy Analysis and Environment Division.

Japanese Challenge in Coal Combustion Technology

About 10 years ago, the Japanese utility industry used no coal. Now Japan rapidly becoming a world leader in applying the state of the art in pulverized-coal-fired electricity generating technology.

"The rapid development of coal combustion technology and facilities in Japan is both exciting and disturbing," reports Kurt Yeager, director of EPRI's Coal Combustion Systems Division. "Exciting in that utility technology developed originally in the United States is being improved and implemented successfully. Disturbing in that the Japanese have seized the initiative and are able to make technical and commercial progress where the United States is unwilling or unable to do so."

The U.S. market for coal-fired systems fell off dramatically in the 1970s and is expected to recover only partially in the next decade. As U.S. suppliers turn toward the growing international markets, particularly those in the Third World, they will find their technical leadership challenged by Japan.

Yeager's observations stem from a visit to Japan with other senior EPRI management as part of scheduled biennial meetings with managers at the Central Research Institute of the Electric Power Industry (CRIEPI). In addition to discussions at CRIEPI, Yeager's visit included stops at facilities of Japan's Electric Power Development Co., Tokyo Electric Power Co., and Mitsubishi Heavy Industries.

"I observed no technological or management breakthroughs during my visit," says Yeager. "The Japanese are simply applying the best technology, much of it pioneered in the United States, with more concerted attention to design, engineering, operating, and maintenance practices than is typical in this country. At this point, I judge they have the capability and, just as important, the commitment to design, build, and operate coal-fired plants as well as anyone in the world. This is evidenced by their competitiveness in the international market and by their domestic accomplishments."

The approach taken by the Japanese has been to carefully examine conventional coal-fired power plant experience throughout the world and to objectively integrate the best elements with no constraints or biases in terms of traditional practices and procedures. In some areas, such as instrumentation, NO_x control, and coal pulverizers, they have made technology advances of their own. However, their basic advantage results from better integration and attention to detail in implementing technology.

In this, they seem generally content for the time being to leave development of revolutionary technology to others. Advanced coal-based options are of interest in Japan, but primarily for longer-term application—probably beyond this century. In the interim, their analyses indicate that under many circumstances, conventional coal-fired generating technology can produce electricity at costs and with efficiencies equivalent to those projected for the more advanced options.

The Japanese emphasis could have important repercussions for the preeminent position of U.S. power plant manufacturers and suppliers. In the same manner as Japanese automakers moved into the U.S. automobile market, their strong focus on integrating and improving the best of conventional technology could enable them to begin chipping away at the market for power generation and auxiliary equipment in this country, as well as internationally through licensing or supply. This rapidly provides the experience and market base for leadership in the more innovative advances in technology.

All plants to be built in Japan will function under supercritical steam conditions (i.e., at pressures above 3450 psi; 23.8 MPa) and incorporate a high degree of fuel flexibility, improved instrumentation, integrated environmental controls, and various other technology improvements at both component and system levels. Because of rate structures and higher fuel costs in Japan, emphasis is also being placed on reducing lifetime costs as opposed to minimizing capital investment. Notwithstanding this, capital costs are competitive with those of conventional pulverized-coal-fired plants now being installed in the United States.

According to Yeager, the key to Japan's success in advancing conventional coal-fired technology is its willingness to objectively evaluate equipment options and design, operating, and maintenance practices on the basis of value, not past practices and tradition. The Japanese are willing to regularly and critically evaluate their practices in an effort to pinpoint potential improvement.

On returning from his second visit to Japan, Dan Giovanni, program manager in the Coal Combustion Systems Division, pointed out that there has never been any serious concern in Japan, as there has been in the United States, that reliability and efficiency might be in conflict. Once the Japanese utilities recognized the efficiency advantages that could be realized with supercritical steam conditions, they aggressively pursued them. After having identified the best available technology, they purchased it on the assumption that when it was installed and in place it would represent the best available power plant.

A second important factor in their success is that Japanese manufacturers have taken an aggressive position in product development and do so in close cooperation with their utility clients. In return, Japanese utilities invest heavily in providing development and demonstration facilities and appear to have more effective control over development of technology for their use. Government support in this process is also critical, with government, industry, and utilities working together rather than at odds with one another.

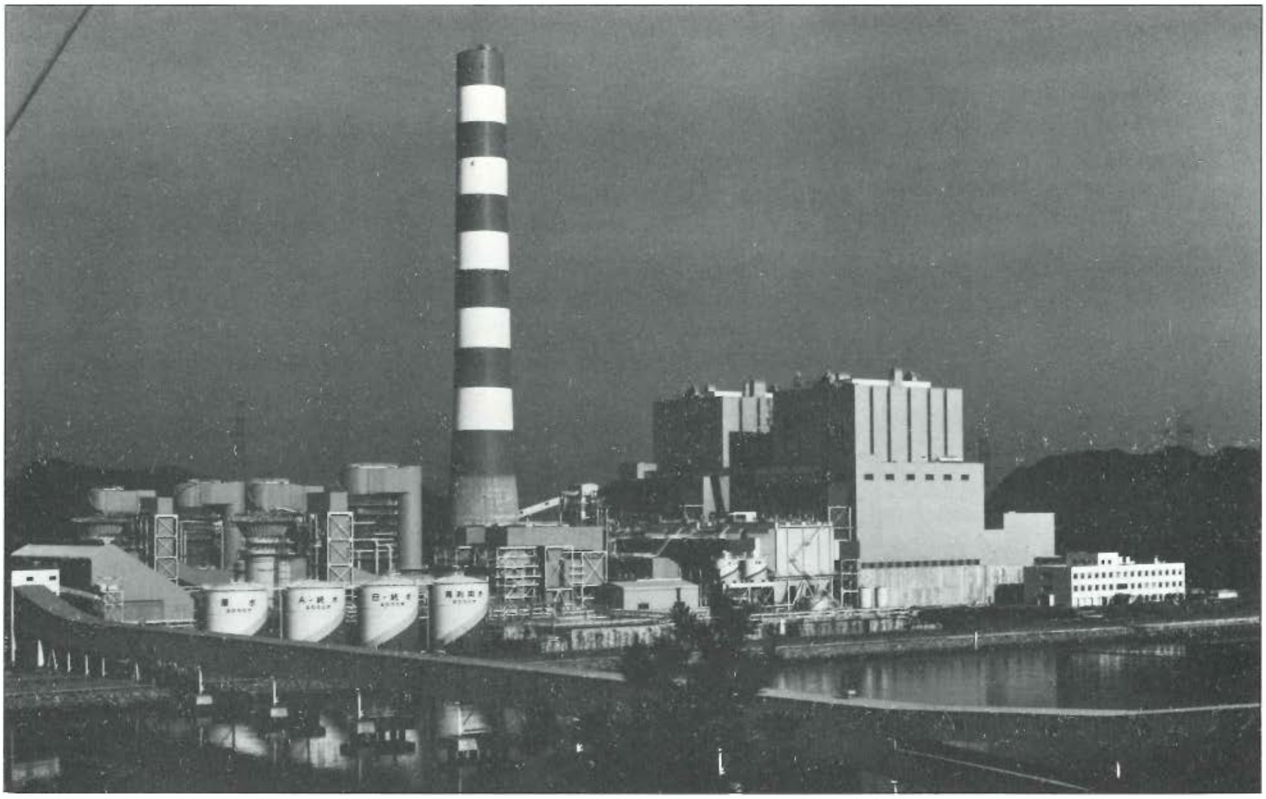
"Their 'secret,'" contends Yeager, "seems to be a higher sense of responsibility to do the job right than we in the United States generally now apply. They are convinced that their commercial success and resulting national survival depend on this dedication. Also, key decisions are made in a more timely manner, based on consensus. This approach is dramatically reflected in the scheduling of siting and licensing procedures." The results attainable by this philosophy of accord are perhaps best reflected in the siting of the Electric Power Development Co.'s Matsushima Power Station, which was built on a pristine and culturally significant island off the coast of Kyushu near Nagasaki. Commissioned in 1981 five years after license application at a cost only slightly above that of conventional coal-fired plants in the United States, Matsushima is widely believed to be one of the most advanced coal-fired power stations in the world.

It consists of two 500-MW (e), 3600-psi (24.8-MPa), single-reheat, supercritical units of licensed U.S. design; combustion NO_x control; hot-side electrostatic precipitators; and an SO_2 scrubber capable of handling the full flue gas flow for each generating unit.

Matsushima is a baseload plant. Net heat rate is about 9200 Btu/kWh, and the load change rate is nominally 1% a minute, although the plant has been tested up to 3% a minute. It is designed to use coal from Australia, China, Canada, and the United States, and it has totally enclosed coal-handling and -unloading facilities for ships of up to 60,000 tons capacity.

In addition to operating at supercritical steam conditions and having the flexibility to use a variety of different coals, Matsushima has a number of other key characteristics.

□ Improved instrumentation and human factors design. In this regard, there are two independent control rooms that present more data in a far more readable form than do their U.S. counterparts. Also, plant control appears to be more precise, and diagnostic instrumentation for maintenance planning is much more extensive.



Japan's current target for developing conventional pulverized-coal-fired technology is a 5000-psi (34.5-MPa) supercritical plant operating at 1200°F (649°C) with two reheats to 1100°F (593°C). The plant would also incorporate reduced power consumption by the auxiliary equipment and a higher performance by the air preheater. This is projected to provide a 7% improvement in efficiency at the busbar (from 36.7% to 39.3%) and to result in a coal combustion reduction of 160,000 tons a year for a 1000-MW (e) plant.

The capital cost increase over a 1000-MW (e), 3500-psi (24-MPa), 1000°F (538°C) single-reheat plant is estimated at $45 million ($45/kW), with annual fuel savings of about $12 million a year ($3/MBtu). For lower-risk steam conditions of 4500 psi (31 MPa), 1050°F (560°C), the additional capital cost is $27 million.

Technical issues identified for emphasis by the Japanese include verification of the reliability and long-term behavior of various alloys at high temperatures. Because variations in temperature and pressure, kind and quality of fuel, and flue gas composition may affect reliability, they feel this must be verified on an actual plant. Development requirements include high-temperature boiler tube alloys; two-stage superheat steam temperature control methods; design of turbine main steam valve, rotor, and blade material; and safety, shutoff, and drain valves.

These improvements would be developed in a step-wise manner to ensure reliability. Initial efforts begun in 1981 focus on qualifying materials at 1100°F (593°C) and then advancing to 1150°F (627°C).

Construction of a commercial plant incorporating 4500 psi (31 MPa) and 1050–1100°F (560–593°C) steam conditions is planned to begin by mid-1986 and to be completed in 1990. Beyond this, construction is to begin in 1990 and be completed in 1995 on a plant representing first commercial application of the full 5000 psi (34.5 MPa), 1150–1200°F (627–649°C) steam conditions. Estimated development costs over the period 1981 to 1987 are about $20 million. □

□ Maintenance practices. Each generating unit in Japan must be shut down annually to undergo a detailed inspection and maintenance period. This typically lasts for three or four weeks and is quite extensive, with about 100,000 man-hours expended. Maintenance personnel are trained and assigned specific job functions rather than being rotated through the plant.

□ Components. The Japanese concluded, for example, that pulverizer reliability was substandard and have undertaken development of fundamentally improved technology. This effort appears to be very successful.

□ Environmental control. The Japanese view environmental control as an integral part of their power plants and lay great emphasis on designing these plants as combined combustion and environmental control systems. As a result, a high level of emission control has been accomplished while minimizing the impact on plant performance and reliability. They are also required to meet stringent NO_x control performance and have implemented an intensive development effort resulting in burner designs that produce half the NO_x emissions typical for a new plant in the United States, while maintaining combustion efficiency.

□ Improved reliability. Reliability levels for Matsushima and other coal-fired plants planned by the Japanese, while all include extensive particulate, SO_2, and NO_x control, are above the U.S. industry average—but comparable to that of the best U.S. facilities with less auxiliary environmental control. This has been accomplished by dedicating maintenance capability, by maintaining adequate margins in design and operation, and by focusing the necessary development work on critical components and auxiliaries.

In an effort to further assess and evaluate advances the Japanese are making in these areas, EPRI is now organizing a mission of utility industry delegates from across the country to examine Japanese power plant practices in detail. It is anticipated that approximately 15 individuals will make up the group, 3 from EPRI's Coal Combustion Systems Division and 12 from diverse utilities, with expertise in such areas as environmental control, plant design and engineering, plant operation, and financing.

Once the mission is assembled, six study groups will be formed, one each to look at boilers, turbine generators, air pollution control, water pollution control and solid-waste management, auxiliary equipment, and overall plant design. The primary objective is to produce an in-depth analysis of Japanese power plant technology and practice, including a thorough assessment of engineering and construction practices, costs, thermal and environmental performance, and unit availability. This information will then be documented and interpreted by the delegates and EPRI staff, and subsequently published by EPRI.

"Many of the changes the Japanese have incorporated, many of the advances they've made, and many of the practices they've adopted are the result of attitudes we in the United States would do well to consider," comments Yeager. "Primary among these is a willingness to constantly and critically examine our practices and procedures on a value basis and not on the basis of tradition. Beyond this, closer cooperation between utilities, equipment and plant designers and manufacturers, and government would be an important step.

"Because of the differences between our societies, our economic situations, energy mix and needs, and the like," Yeager explains, "adopting this philosophy wouldn't necessarily mean we would wind up making the same decisions as the Japanese. But we should recognize that if we do not make some adjustments, some changes, our preeminence in coal utilization in both domestic and world markets is threatened. In that event, our only likely option to maintain the same levels of performance 5 to 10 years hence would be to rely on foreign technology."

The strategy Yeager recommends to maintain the U.S. edge in technology is to use the present period when little new capacity is being committed here to step up our efforts to monitor Japanese technical development programs and power plant experience; to implement selected parts of the Japanese approach to power plant design and operation, taking a hard-nosed attitude on what will work best for us as opposed to incremental changes in the way we've always done it; and to pursue an aggressive U.S. development program on those advances having merit for both domestic and international conditions.

An important effort is already under way within the utility industry through EPRI's work to characterize the potential for advancing pulverized-coal-fired plant performance. This will include validation of and designs for both new and retrofit applications. Moreover, an 18-month, EPRI-sponsored planning program will soon begin to consider scheduling, development tasks, and costs to validate these power plant technology improvements and develop application guidelines with the utility industry. For these efforts to be successful, however, Yeager underscores that the strong commitment and joint participation of U.S. power plant manufacturers and suppliers are required.

"EPRI looks forward to working with U.S. manufacturers and suppliers to maintain the technical leadership needed for improving pulverized-coal-fired performance and reliability," he says. "Clearly, joint user-supplier efforts in this area will be required to make it possible for U.S. utilities to continue to look domestically for the technology they need to maintain the most efficient and reliable operation of conventional coal-fired power stations and for U.S. suppliers to compete successfully in the world market."

This article was written by William Nesbit, science writer. Technical background information was provided by Kurt Yeager, director, Coal Combustion Systems Division.

Energy Forecasts by EIA

The Energy Information Administration's *1981 Annual Report to Congress* presents statistical projections of U.S. energy supply and demand.

Since 1977 the Energy Information Administration (EIA) of DOE has been responsible for gathering, analyzing, and disseminating energy statistics. Uniquely, the statistical and analytic materials EIA provides are not subject to the approval of any government official other than its own administrator, who is appointed by the president and approved by the Senate. This independent position is designed to allow EIA to function in an objective manner when evaluating future trends in energy supply and demand. The agency neither sets policy nor issues regulations. It simply manages a comprehensive set of energy models and data bases that are designed to deliver the necessary information for energy policy analysis and contingency planning.

As required by law, EIA's *1981 Annual Report to Congress* provides projections based on energy production and consumption and prices based on models developed within EIA. The projections focus on U.S. energy markets over 15 years (1980–1995), as well as long-range domestic energy production and consumption forecasts for the years 2000 and 2020. EIA collects the data used in its models by surveying industries, businesses, organizations, and households, in addition to obtaining data from forms filed by electric utilities with the Federal Energy Regulatory Commission and with DOE on existing capacity, monthly fuel use, and generation.

J. Erich Evered, EIA administrator, notes in his foreword to the 1981 report, "The EIA approach . . . attempts to account for future uncertainty as reasonably as possible, but the projections should not be viewed as unqualified statements about the future, nor should they be taken out of context and treated as if they were certain. To repeat the admonition in last year's report—there are no facts about the future."

With Evered's cautious note in mind, the report goes on to state that higher world oil prices have caused a historical shift in patterns of energy production and consumption and that this shift will cause total energy consumption over the next 15 years to grow at rates far below those of the last three decades. This low growth is mainly a result of increased efficiency in energy use by all sectors of the economy.

EIA projects that total domestic energy supply for 2000 will reach 104 quadrillion Btu, compared with 79 quads in 1980. (Total supply is the sum of domestic energy production plus net energy imports, excluding imports for the Strategic Petroleum Reserve.) To emphasize that projected domestic supply has slowed somewhat, EIA's 1979 report predicted that energy supply in 2000 would reach 108 quads. Such is the effect that conservation and high oil prices have had on existing energy markets.

Assumptions Behind Projections

Underlying EIA's energy projections are assumptions about world oil prices, growth in gross national product (GNP), inflation rates and other economic aggregates, and government energy programs.

The report notes that between 1973 and 1980 the nominal world oil price

EIA ENERGY SUPPLY AND DEMAND PROJECTIONS, MIDPRICE CASE

(quadrillion Btu per year)

	History	Projections		
	1980	1990	2000	2020
Domestic energy supply				
Oil	21	20	21	17
Natural gas	20	18	18	15
Coal	19	27	41	77
Nuclear	3	8	11	18
Other (hydropower, solar, geothermal, and biomass)	5	7	11	19
Subtotal	68	80	102	146
Net imports				
Oil	13	12	8	3
Natural gas	1	1	1	0
Coal	−3	−4	−6	−6
Subtotal	11	9	3	−3
Total energy supply	79	89	105	143
Domestic energy demand				
Residential	9	10	11	12
Commercial	7	7	9	10
Industrial	23	31	36	47
Transportation	19	18	19	19
Total end-use demand	58	66	75	88
Stock changes, accounting errors, and transmission losses*	21	23	30	55
Total energy demand	79	89	105	143

Source: Energy Information Administration, *Monthly Energy Review*, November 1981, and *Natural and Synthetic Gas, 1980* (an Energy Data Report). Estimates of energy end-use consumption were based on data from the State Energy Data System. Projections were derived by using the LEAP model.

*Transmission losses are about 9% for natural gas and electricity.

rose from roughly $4 a barrel to more than $35 a barrel, for an average annual increase of 31% per year. EIA expects oil prices in the long term to continue upward but at a less rapid rate. In its midprice case, EIA projects that the world oil price (in 1980 dollars) will be $33 a barrel in 1985; $49 a barrel in 1990; $67 a barrel in 1995; $75 a barrel in 2000; and $90 a barrel in 2020. EIA emphasizes that the behavior of OPEC is a critical factor in determining future oil prices. In its midprice scenario, EIA assumes that OPEC will continue to set prices in much the same manner as it has done since 1974—that is, OPEC members will either raise or lower prices as needed to maintain world demand for OPEC oil at roughly 80% of OPEC's production capacity.

Assumptions about aggregate economic growth rate used in the report imply an annual average growth rate of real U.S. GNP of 2.7% between 1980 and 1995 for the midprice world oil case. The report notes that although this growth rate is lower than that experienced in the 1970s, it is in keeping with the historical growth rate of the U.S. economy.

Regarding the influence of federal energy programs on energy projections, the report states that an attempt has been made to incorporate in the projections those programs (such as energy and environmental regulations) that affect specific energy industries. It is the policy of EIA to base its projections on statutes and regulations that exist at the time the projections are prepared. As a case in point, there have been recent discussions in the government on modifying the Natural Gas Policy Act of 1978, which provides for the elimination of controls on the wellhead prices of certain categories of natural gas by January 1, 1985. The modifications to the act would provide for earlier or more extensive deregulation. The EIA projections, however, assume that decontrol will occur as scheduled in the act.

The change in two statutory requirements, however, has affected EIA's 1981 report projections. The federal tax code was altered by the Economic Recovery Tax Act of 1981. The projections, therefore, incorporate any changes affecting energy industries, such as greater incentives for financing of investor-owned public utilities and reductions in the windfall profit tax on new oil. In addition to the tax changes, the Omnibus Budget Act of 1981 amended the Power Plant and Industrial Fuel Use Act of 1978 to eliminate provisions that required electric utilities to limit their use of natural gas to generate electricity after 1990. The amended act allows electric utilities with existing gas-powered generating facilities to choose the fuel mix best suited to their markets. This particular statutory change had a significant impact on the report's projections.

With an understanding of the assumptions behind the energy future projected by EIA, it is now possible to evaluate the projections for domestic energy markets through 1995. EIA addresses end uses of energy, electricity generating, and oil refining (the conversion sectors), as well as primary energy supplies or fuel sources.

Electricity Projections

The report notes that before the Arab oil embargo of 1973–1974, electricity consumption increased at an average annual rate of more than 7%. Since 1974 the real price (the price above inflation) of electricity has constantly risen, and all users of electricity—residential, commercial, and industrial—have reacted by instituting conservation measures and improving equipment and appliance efficiency.

EIA predicts the increase in the consumption of electricity will be both absolute and relative to other forms of energy. Despite a rise in real price, EIA projects that electricity prices will increase more slowly than the prices of other major sources of energy, thereby making it a more likely substitute for other energy sources. The report states that electricity's share of the end-use energy market will increase to 16% of the total energy consumed in 1995, compared with 12% in 1980. The industrial sector is expected to consume the largest share of electricity in the midterm—that is, 42% of total electricity demand by 1995, up from 39% in 1980.

In terms of primary energy supply, EIA foresees that coal and uranium will replace oil and natural gas in the midterm as sources of electricity generation because of increasing oil and gas prices. The report states that the additional expenditure required to build new nuclear and coal plants is usually offset by the savings in fuel costs that result from using coal or uranium instead of oil and gas.

In 1980 oil and gas fueled 26% of electricity generation. In 1995, however (finances permitting), the displacement of existing oil and gas plants with new nuclear or coal plants will be responsible for reducing the combined oil and gas share in electricity generation to only 8%. Coal is projected to provide 61% of electricity generation in 1995, compared with 51% in 1980. Generation by nuclear power is forecast to increase to 21% in 1995, up from 11% in 1980. It is worth noting that because of the long construction lead times of coal and nuclear plants, the impact of the projected increase in their capacity will not begin to be pronounced until the years 1990–1995.

An interesting aspect of this year's annual report is the inclusion of a sensitivity case in EIA's projection as a result of the financial constraints on the electric utilities. Because of the high cost of fuel, labor, inflation, and high interest rates, and the lower-than-expected demand growth, many utilities have had to cancel or postpone new construction projects. EIA's sensitivity run assumes that only nuclear plants currently more than 20% complete and coal plants with at least one boiler ordered would be completed by 1995, allowing for only 113 GW of coal-fired capacity built during 1980–1995 and only 72 GW of nuclear capacity completed. The midprice case, with no financial constraints, projected 173 GW of coal capacity in the same period and 84 GW of nuclear power capacity.

Betsy O'Brien, analyst in EIA's electric power division, explains, "In the financial constraint case, we are looking at reliability through 1995 with a more pessimistic outlook. Even by factoring in delays in coal and nuclear plant construction, we can still meet electricity demand in 1990 but at much higher prices."

Overall, the report's midterm forecast presents no dramatic changes for the U.S. energy future. The midterm projections foresee no severe reductions in oil and natural gas supplies, nor do they predict large shifts to new energy technologies in the next 15 years. The projections also do not suggest an end to U.S. dependence on imported oil.

Energy in the Long Term

The report's chapter on energy in the longer term assesses the potential role of new energy technologies in reducing U.S. dependence on scarce, nonrenewable energy sources. The conclusion is that it seems unlikely that extensive use of any new energy technologies will occur by 1995 because of high costs and delays in the adoption of new products.

EIA does not see much hope for commercial electricity generation by either nuclear fusion or breeder reactors before 2000. The report states that by 2000 the major new utility technologies are likely to be nonnuclear—either technologies using renewable sources (such as solar-thermal, geothermal, wind) or nonrenewable advanced technologies (such as gasification–combined-cycle power plants, fluidized-bed combustion, fuel cells). EIA notes that DOE and EPRI have supported R&D in both of these areas.

In the renewables group, EIA assumes that large wind systems will be commercially available by 1985, although they

ELECTRICITY GENERATION

Source	Percent of kWh 1980	Percent of kWh 1995
Coal	51	61
Oil	11	3
Natural gas	15	5
Nuclear	11	21
Other	12	10

are expected to produce relatively small amounts of electricity by 2000, and forecasts that wind systems integrated into utility systems may produce only 0.3 quadrillion Btu of generation by 2020. EIA also predicts that electricity generation by geothermal sources will remain relatively stable through 2000 but could add 0.7 quad of capacity by 2020. EIA foresees that central station solar-thermal technology should be commercially available by 1985, but will produce only 0.1 quad of electricity by 2000 and 0.4 quad by 2020. And the report sees little hope for a contribution by ocean-thermal energy conversion technology until after 2020 because of high capital costs and lack of available sites.

EIA finds more immediate promise in the advanced nonrenewable technologies, some of which improve the efficiency of coal-based electric generation. Regarding development of coal gasification–combined-cycle systems, the report states that two demonstration power units involving the Texaco, Inc., medium-Btu gasifier and the Combustion Engineering, Inc., low-Btu gasifier should be operating by 1985. EIA predicts that the technology could be commercially available by 1990 and could produce 0.6 quad of electricity generation by 2000 and possibly 1.7 quads by 2020. The report also projects that atmospheric fluidized-bed technology should be commercial by 1990, producing 0.1 quad of electricity by 2000 and 1.6 quads by 2020. In discussing the phosphoric acid fuel cell currently being tested by Consolidated Edison Co. of New York, Inc., under funding by EPRI, DOE, and United Technologies Corp., EIA finds that it should be commercially available by 1985, while the molten carbonate fuel cell will not be available until 1990. EIA predicts that fuel cells will contribute 1.0 quad to the domestic energy supply by 2020.

Nuclear power is seen by EIA to be a major contributor to electric generation in the long term. However, a central uncertainty is the timing in the resurgence of nuclear orders. If the current backlog of nuclear units already ordered is filled and new orders appear, EIA projects that nuclear power should supply about 30% of the nation's electricity in 2020 (285 GW). The report emphasizes that to reach this level of capacity, a long-term ordering and construction rate of about 12 GW/yr would be necessary, half of which would replace existing nuclear capacity scheduled for retirement.

Yet the report also sounds a warning note about constraints on nuclear development. "Lacking a nuclear power option could press total coal requirements to levels even higher than those projected in the midprice case. Such increased competition for coal could raise prices, place large demands on the coal transportation infrastructure, and possibly delay prospects for a coal-based synthetic fuels industry."

In its final analysis, EIA foresees the role of electricity continuing to increase in the long term. The report projects that growth rates for electricity generation will be 2.5% a year for 1980–2000 and 2.0% for 2000–2020. These growth rates are moderate by historical standards, but there will be an increasing fraction of total primary energy consumed to generate electricity. EIA also notes that electricity will substitute for many conventional oil and gas technologies, and by 1990, utility electricity will account for 14% of net energy consumed, growing to 16% by 2000 and to 20% (or 17 quads) by 2020. ■

This article was written by Christine Lawrence and Ellie Hollander, Washington Office.

Metals From Fly Ash

Reclaiming metals and other by-products from coal fly ash could offset waste disposal costs for utilities.

Research under way at EPRI indicates that coal fly ash currently discarded as waste contains a sizable resource of aluminum, iron, and various other metals. A new acid-leaching process being tested by the Institute may provide an economically attractive way to remove some of these metals.

Coal-fired power plants produce a great deal of fly ash—some 400,000 tons a year from a 1000-MW facility—but only about 20% of this material is being put to beneficial use. Metals are found in coal naturally, and burning the coal concentrates them in the ash. In some cases 30–35% of the ash may be metals that could be reclaimed.

The new EPRI process seems to be most attractive for extracting aluminum and iron from coal ash. Laboratory work carried out for EPRI by the Oak Ridge National Laboratory proved the small-scale feasibility of the leaching process for the removal of these metals, and an economic analysis performed concurrently indicated that operation of the process on a large scale might be profitable for utilities because of revenues from the sale of reclaimed ores.

EPRI has completed the initial work on the extraction process and is currently considering a three-year, $600,000 scale-up. That work should give researchers more information on the quality of metal products that can be extracted from fly ash and on the economics of operating the system on a large scale.

According to Project Manager Dean Golden, ore reclamation is only part of the story. Another process, developed by Halomet, Inc., and now being tested by West Penn Power Co., is designed to extract magnetite, a mineral used in coal cleaning, from fly ash.

In addition, some fly ashes can partially substitute for portland cement as an ingredient in concrete because these fly ashes are pozzolans. (A pozzolan is a silicon-based material that can be combined with lime and water to form a cement that is stronger, more workable, and less permeable than portland cement.) "Fly ash–based cements actually become stronger over time rather than deteriorating," Golden commented. "This is because air and water, the substances that cause the breakdown of normal cement, cannot get into these pozzolanic cements. The Colosseum in Rome was built with cement made with naturally occurring pozzolans."

Such cements are also far less expensive because fly ash is readily available at a low cost and does not need to go through the energy-intensive sintering process used in the manufacture of normal cement. "The sintering occurs when the coal is burned," Golden explained. "Basically, all the energy-intensive work is free when fly ash is used."

Golden said he sees the possibility of a utility setting up a multistep coal ash processing system that first removes the magnetite, then removes the aluminum, and then sends the residue to a cement factory, effectively eliminating the ash waste from the coal plant. At the same time the system is generating revenue for the utility through the sale of recovered by-products, the processing saves the cost of ash disposal. It also saves the metal and cement industries money for raw materials and manufacture and helps the environment by using the waste rather than putting it back into the environment.

High School Assembly Program Hits the Road

During the past several months, electric utilities around the country have been previewing a new educational program called "The Electric Connection." This 45-minute interactive program is designed to provide high school students with a better understanding of the complexity of the current energy situation in the United States.

EPRI provided funds and technical assistance for the development of the program, which was put together by the Energy Education Division of Oak Ridge Associated Universities (ORAU), a nonprofit organization sponsored by 23 colleges and universities. "The Electric Connection" is the latest effort in ORAU's 20-year history of producing school assembly programs. Previous titles include "This Atomic World," "Energy Today and Tomorrow," and "Energy Adventure."

Utilities that preview the show during its road tour are examining it for use by high schools in their service territories.

"The Electric Connection" emphasizes R&D activities as vital elements in meeting the energy challenge of the future. The primary message is that electric power comes to the consumer through a complex, closely interwoven transmission and generation system and that the variable nature of electric demand places unusual stresses on the system.

"We saw a need to get this kind of information into the high schools through our member utilities," said Communications Programs Manager David Ulrich. "ORAU has a very good track record for producing high-quality shows."

Mobile Lab Tracks Bird Migration

EPRI has developed a mobile laboratory that may soon be helping electric utilities to secure rights-of-way for electric transmission lines. Historically, one objection to proposed overhead lines has been that they will interfere with bird flight patterns—particularly those of migratory flights. In hearings on the subject, the utility must prove a line will not be a hindrance to birds before a right-of-way is granted. Until now, proof has been difficult because most birds do their long-distance flying at night. Moreover, there were no methods for quantifying bird activities in relation to power lines.

EPRI and Sidney Gauthreaux, professor of biology at Clemson University, have teamed up to develop an automated bird watcher. Gauthreaux, who is an expert in bird migration patterns, combined commercially available radar, night-vision devices, and a computer analysis capability into a mobile laboratory—a modified recreational vehicle—designed to track bird flight patterns in an area. The combined use of radar and night scope permits the operator to identify the number of birds, their range and altitude, and in some cases, their species, even during periods of low visibility. The data are stored on computer tape for later analysis. Development and testing costs are expected to total $600,000.

John Huckabee, EPRI project manager, said the laboratory will be field-tested at sites around the country until late autumn of this year. If the results are positive, the unit will then be made available to utilities for their use.

A utility planning a power line will use the laboratory for several seasons to guarantee accurate data on the bird flight patterns in a particular area. Despite the time and effort this involves, Huckabee believes utilities will welcome the device if its use ensures they can site lines away from bird populations.

Additional applications may exist outside the utility industry. Almost any right-of-way acquisition effort could benefit from advance notice of bird activities in the area. In addition, radio and television transmission towers could be sited to minimize the likelihood of bird collisions.

Information Coordinators Briefed

One of the main information links between EPRI and its members is the technical information coordinator within a given utility. To help coordinators become more familiar with existing technical information resources and services, EPRI's Technical Information Division (TI) hosted a series of one-day seminars earlier this spring.

The meetings, conducted by Olga Compton, technical information services specialist, provided an overview of EPRI and the Information Services Group, and then zeroed in on TI's services—covering strategies for identifying and obtaining specific R&D information.

TI publishes several index volumes that can help coordinators locate information about particular research areas, including the *Digest of Research in the Electric Utility Industry*, the *EPRI Guide*, and *Research and Development Projects*.

About 100 technical information coordinators and utility managers from around the country attended the seminars. Representatives from Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association also participated.

A separate series of workshops is being held this month for R&D engineers, technical information specialists, and data base users from member utilities.

CALENDAR

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

MAY

13–14
Utility Seminar: Municipal Solid Waste as a Utility Fuel
Miami Beach, Florida
Contact: Charles McGowin (415) 855-2445

18–21
Symposium: Flue Gas Desulfurization
Hollywood, Florida
Contact: Stuart Dalton (415) 855-2467

19–20
Seminar: Improvements in Power Plant Casting Quality
St. Charles, Illinois
Contact: Adrian Roberts (415) 855-2053

25–27
International Conference: Penetration of Electricity in Industry
Montreal, Canada
Contact: Walter Esselman (415) 855-2331

JUNE

2–4
Symposium: Power Plant Feed Pumps
Cherry Hill, New Jersey
Contact: Isidro Diaz-Tous (415) 855-2826

7–11
HV Transmission Line Design
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

7–11
Foundation Design of Transmission Line Structures
Dallas, Texas
Contact: Phillip Landers (415) 855-2307

14–18
HV Transmission Line Design
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

16–18
Symposium: Environmental Analytic Chemistry
Provo, Utah
Contact: Glenn Hilst (415) 855-2591

JULY

7–9
Workshop: Steam Turbine Blade Reliability
Boston, Massachusetts
Contact: John Parkes (415) 855-2451

14–15
Seminar: Current Electrostatic Precipitator Technology
Nashville, Tennessee
Contact: Walter Piullet (415) 855-2470

15–16
Torsional Fatigue Strength of Large Turbine Generator Shafts
Denver, Colorado
Contact: Dharmendra Sharma (415) 855-2302

28–30
Environmental Control Technology for Coal Gasification Processes
Palo Alto, California
Contact: William Reveal (415) 855-2815

AUGUST

2–6
HV Transmission Line Design
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

9–11
Conference: Power Plant Availability
Dearborn, Michigan
Contact: David Poole (415) 855-2458

9–13
HV Transmission Line Design
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

16–20
Foundation Design of Transmission Line Structures
Denver, Colorado
Contact: Phillip Landers (415) 855-2307

25–27
Incipient Failure Detection for Fossil Plant Components
Hartford, Connecticut
Contact: Anthony Armor (415) 855-2961

SEPTEMBER

8–10
Workshop: Steam Turbine Bearings and Rotor Dynamics
Detroit, Michigan
Contact: Tom McCloskey (415) 855-2655

20–22
International Conference: Compressed-Air Energy Storage and Underground Pumped Hydro
San Francisco, California
Contact: Robert Schainker (415) 855-2549

OCTOBER

13–15
Transmission Line Grounding
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

18–20
Substation Grounding
Atlanta, Georgia
Contact: John Dunlap (415) 855-2305

25–27
7th International Conference on Fluidized-Bed Combustion
Philadelphia, Pennsylvania
Contact: Shelton Ehrlich (415) 855-2444

NOVEMBER

2–4
Seminar: Hydro Operation and Maintenance
Atlanta, Georgia
Contact: Charles Sullivan (415) 855-8948

14–18
National Fuel Cell Seminar
Newport Beach, California
Contact: Edward Gillis (415) 855-2542

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Director

ADVANCED COAL LIQUEFACTION

In the past it has been found that there is a practical upper limit to the yield of liquid products obtained by hydroconversion of a given coal. This upper limit has usually been assumed to be in the range of 40–50% of the moisture- and ash-free coal and can usually only be achieved at very severe process conditions. It is these severe process conditions and low conversions that are responsible for the relatively high costs associated with coal liquefaction. Recent research at the laboratory scale, however, has demonstrated that with the use of particular types of solvents, it is possible to achieve almost complete conversion of coal to liquid products under relatively mild process conditions.

It has generally been accepted that coal is composed of polyaromatic, heterocyclic, and alicyclic structures that are linked by aliphatic and ether bridges. With geological age, as coal is subjected to temperature and pressure, it becomes increasingly aromatic and more extensively crosslinked. Yet there has always been some speculation that coal may not be as refractory and polymeric as it appears, but instead may be rather reactive, containing structural units of relatively low molecular weight. This speculation has been based on inconsistencies observed in the experimental data.

Recent liquefaction research may support such speculation. It implies that coal may be predominantly held together by hydrogen bonding and weak thermal bonds. It has been found that with the use of certain solvents and under proper liquefaction conditions, coal can be efficiently converted to a liquid with a minimum use of hydrogen and a minimum yield of gaseous products. These results represent the best evidence to date that coal exists in a very unusual state. Although superficially coal appears to be a refractory, nonreactive solid, if it is handled properly, it can easily "unravel" into a liquid product. The solvents that have been found to perform this function most effectively are basic nitrogen heterocycles.

These effective nitrogen heterocycles are Lewis bases. A Lewis base can interact with other molecules in at least two ways: It can partially accept a hydrogen atom attached to another molecule, thus setting up a hydrogen bond, or it can donate an electron pair to form a coordinate bond.

The mechanisms by which the basic nitrogen solvents work are still not fully understood. There are several plausible ones, and in all likelihood, several are occurring. Additional research will be needed to understand fully these complex phenomena; an explanation of only one of the more probable mechanisms follows.

Hydrogen bonding in coal and coal liquefaction

Hydrogen bonding is an attractive force, or bridge, occurring between a hydrogen atom and a fluorine, oxygen, or nitrogen atom. This bonding can exert profound effects on the physical properties of a material (e.g., boiling point, melting point, and solubility) and also plays a key role in determining the shapes of large molecules. (It is now accepted in biochemistry that hydrogen bonding is critically important in determining the shape of large molecules like proteins and nucleic acids. It is, in fact, hydrogen bonding that causes the double helix of DNA.) In coal, hydrogen bonding may exist between either a nitrogen or an oxygen atom and a hydrogen atom that is covalently bonded to an oxygen or a nitrogen atom. Thus four types of bonds are possible: N...HO, O...HO, N...HN, and O...HN.

A possible hypothesis is that during coal liquefaction, hydrogen bonds are broken as coal is heated to reaction temperature. Once these bonds (attractive as opposed to covalent) are broken, molecules then become free to react at the exposed labile sites. (Labile sites are sites readily able to undergo chemical or physical change.) Retrogressive reactions, such as condensation and polymerization, proceed at these sites if molecular hydrogen is not readily available. This phenomenon occurs particularly during the early stages of coal dissolution, when the activation energies for the condensation and polymerization reactions are considerably less than that required for hydrogen transfer from the coal, a donor solvent, and/or diatomic hydrogen. (Activation energy is the minimum amount of energy that must be provided by colliding particles, atoms or molecules, in order for a reaction to occur.) Consequently, by the time hydrogen does become available for transfer, the primary products of coal have already retrogressed to highly refractory, high-molecular-weight, polynuclear hydrocarbons.

Since coal contains more oxygen than nitrogen, there is more oxygen-oxygen hydrogen bonding than oxygen-nitrogen hydrogen bonding in the as-received coal and also during the early stages of coal dissolution (when the weak thermal bonds are breaking). If the coal retains the O...HO hydrogen bonding during dissolution, condensation and polymerization may occur on heating. If, however, a threshold amount of a proton-accepting base is available to break the O...HO hydrogen linkages and yet at the same time engage or tie up those linkages until the temperature is high enough for hydrogen transfer, then the integrity of the initial coal structure will be maintained.

Hydrogen bonding involving a ring nitrogen is probably sufficiently strong to maintain the coal's structural integrity by preventing the dissolving coal molecules from interacting with each other and/or interacting prematurely with the process solvent. The O...HO hydrogen bonding does not perform this preventive function. If the basic nitrogen compounds are available, they participate in hydrogen bonding until the thermal liquefaction conditions that favor hydrogenation reactions are reached. Then the hydrogen bonding effect diminishes, allowing the desired hydrogenation reactions to proceed.

If it is true that oxygen-nitrogen hydrogen bonding is critical in preventing retrogressive reactions, then the use of a solvent that supplies additional basic nitrogen compounds may be significant in impeding undesirable and irreparable destruction of the coal. Once the retrogressive reactions have occurred, the final coal-derived products may be worse (less reactive, more refractory) than the original coal.

Basic nitrogen compounds

EPRI's first indication that materials containing basic nitrogen compounds are beneficial in coal liquefaction came three to four years ago in work by Pennsylvania State University under a subcontract to Mobil Research and Development Corp. (RP410). Gold-tube experiments were performed on various sequential elution solvent chromatography (SESC) fractions of solvent-refined coal (SRC). When SESC Fraction 5, the basic nitrogen fraction, was reacted in a gold tube at 842°F (450°C) and 5000 psi (34.5 MPa) nitrogen pressure for one hour, little or no coke was formed. In contrast, all other fractions coked profusely, which is an indication of retrogressive reactions. In addition to basic nitrogen compounds, Fraction 5 also contains some phenolic compounds, which are known to condense and polymerize (retrogress) easily. It is possible that in this fraction they were prevented from doing so by the presence of the basic nitrogen compounds.

Two years ago under RP779-25, Gulf Research & Development Co. obtained an interesting and unexplainable result that was ignored by almost everyone until recently: Drying appears to adversely affect liquefaction conversion. The project's objective was to investigate the liquefaction behavior of dried and/or oxidized coal. Western subbituminous coal with a high moisture content (>25 wt%) was used throughout the work. The project produced a number of important conclusions and contributed significantly to the understanding of the detrimental effects of oxidation in the liquefaction of western coals. However, the most startling finding involved the impact of coal drying on liquefaction results. When the subbituminous coal was dried, even in an inert gas, its liquefaction product yield was significantly lower than that of the as-received coal.

The next piece in the evolving picture of coal and its handling came from work by Mobil (RP1655). A 600–800°F (316–427°C) distillation fraction of hydrogenated solvent from the Wilsonville (Alabama) Coal Liquefaction Development Facility was chemically fractionated into generic classes, and the resulting fractions were used in coal conversion experiments. The results are presented in Table 1.

It can be seen that coal conversion is not additive. When the basic nitrogen fraction was used, coal conversion was higher than with any other fraction or with the parent solvent. The calculated conversion value for the whole solvent was 52%. The fact that the actual conversion with the whole solvent was 72.7% indicates the substantial contribution made by the small basic nitrogen fraction (4.4% of the solvent). It was also found that the selectivity to lower-molecular-weight products was greater with the basic nitrogen fraction than with the phenolic or the neutral fraction.

An analysis of the basic nitrogen fraction by Fourier transform infrared (FTIR) spectroscopy indicated the presence of heterocyclic nitrogen compounds. Field ionization mass spectrometry (FIMS) of the fraction indicated that the basic nitrogen structures present were of the types shown in Figure 1.

In studying the analytic workups of all the experiments conducted under RP1655 with both model solvents and process-derived solvents, Mobil discovered that nitrogen-rich compounds were being concentrated in the dissolving coal during the early stages of dissolution. It appeared that the coal was scavenging the nitrogen. During this period the nitrogen content of the insoluble material (dissolving coal) increased from 0.99 to 4.8 wt%. After approximately six minutes at liquefaction conditions, this trend reversed and the nitrogen compounds were again redistributed between the solvent (heptane solubles) and the dissolving coal (heptane insolubles). This observation has some interesting implications pertaining to the structure of coal and the mechanism by which it is converted to liquids.

The effectiveness of a solvent is usually measured by its solvency and its hydrogen donor and/or hydrogen shuttling capability. Basic nitrogen compounds seem to perform well in terms of both criteria. Before 1971 the British National Coal Board established that compounds containing ring nitrogen were particularly effective coal liquefaction solvents; of all the solvents that it studied, 1,2,3,4-tetrahydroquinoline (PY–THQ) was the most effective. Similarly, work performed by Bergbau-Forschung GmbH before 1969 had established that coal could be almost completely dissolved by PY–THQ at very low temperatures (572°F; 300°C).

Early work by Mobil had shown that quinoline can be hydrogenated under typical (or less severe) coal liquefaction conditions even without the presence of a catalyst (RP410). This is unlike the case for the traditionally used naphthalene-tetralin system, where an active catalyst is required to hydrogenate naphthalene to the hydrogen donor tetralin. The hydrogenated quinoline PY–THQ is an extremely effective hydrogen donor—even more effective than tetralin.

Work by other investigators on the chemical equilibria of quinoline and its hydrogenated counterparts has shown that at 1012 psia (7 MPa) hydrogen partial pressure, the maximum hydrogenation of quinoline to tetrahydroquinoline is reached at a reaction temperature of about 775–800°F (413–427°C). This temperature range is of particular interest in light of some recent results at EPRI's 6-t/d coal liquefaction pilot plant at Wilsonville, Alabama (RP1234).

Table 1
COAL CONVERSION IN FRACTIONS OF 600–800°F (316–427°C) SRC-I PRODUCT

Fraction	Portion of Whole Solvent (%)	Coal Conversion (%)
Neutral	82.2	53.7
Phenolic	10.8	37.6
Basic nitrogen	4.4	76.5
Acidic	1.0	—*
Amphoteric	0.4	—*
Whole solvent	100.0	72.7 (52)†

Note: Monterey coal was the test coal. Experiments were conducted at 800°F (427°C) for 1 hour at 1000 psig (6.9 MPa) hydrogen pressure; the solvent-to-coal ratio was 3 to 1.

*Insufficient quantities of these fractions were isolated for conversion experiments.

†52% is the mathematically calculated conversion based on weighted averages of the fractions.

Figure 1 Examples of basic nitrogen compounds. The compound 1,2,3,4-tetrahydroquinoline has been found to be an effective coal liquefaction solvent.

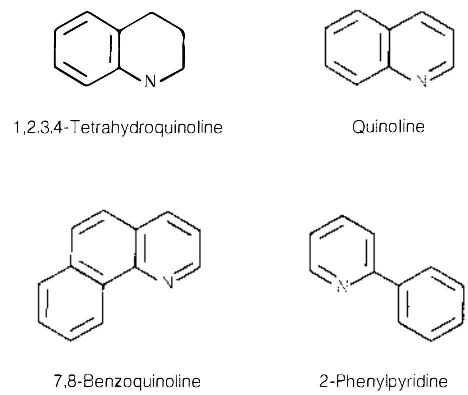
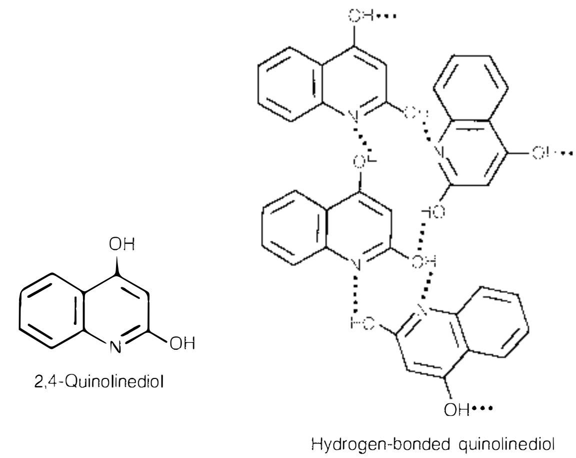


Figure 2 Hydrogen bonding of quinolinediol. The hydrogen bonds (dotted lines) significantly affect the physical properties of this low-molecular-weight material.



It has recently been found that remarkable coal liquefaction performance is achieved at around 1000–1200 psia (6.9–8.3 MPa) hydrogen partial pressure and liquefaction temperatures of 785–800°F (418–427°C). The liquid yields are much higher than anticipated for this temperature range. Traditionally, liquefaction temperatures of 840–850°F (449–454°C) have been assumed necessary. The unusually good Wilsonville performance is achieved by the use of a heavy solvent recycle known as light SRC (LSRC). Early research conducted for EPRI by Conoco Coal Development Co. and Kerr-McGee Corp. predicted that the recycling of LSRC would result in this improvement in coal liquefaction performance (RP1134). The improved performance appears to correlate with solvent composition, including nitrogen content. These results are probably not coincidental. More likely, basic nitrogen compounds are actively participating in the liquefaction of the coal.

Through FTIR spectroscopy, Advanced Fuel Research, Inc., has identified such components as quinoline and tetrahydroquinoline in active coal-derived recycle solvents from various processes (RP1604-2). This work has also shown that hydrogen bonding exists in these solvents and in the coal itself, although it has not yet been determined to what extent.

Other research involving model compounds such as quinolinediol has demonstrated that hydrogen bonding can dramatically change the physical characteristics of a low-molecular-weight material. Like coal, quinolinediol is insoluble in strong solvents, such as hot tetrahydrofuran. Also, it has a high melting point, over 572°F (300°C). However, the compound in fact has a low molecular weight (164) and would usually be a liquid at room temperature. The physical properties of this compound are not the result of covalent bonding and can only be explained by hydrogen bonding (Figure 2).

Early work by Atlantic Richfield Co. aimed at viscosity reduction has also shown the extent of hydrogen bonding in coal liquefaction products (RP626-1).

Thus, from many interesting pieces of data and some anomalies, a picture of coal and how it can be turned into liquids started to be formulated. If the coal is not handled properly, then it is an extremely reactive substance. Presumably, coal has a very unusual molecular structure held together by strong hydrogen bonding in addition to the traditionally accepted covalent bonding. If the coal is not properly handled, either during drying or during the early stages of dissolution, it can thermally degrade into a highly refractory, polynuclear structure. Once this material is formed, high temperature, an expensive catalyst, and excessive hydrogen are required to turn it into a material that is inferior to the original coal.

If the as-received coal is properly handled, however—that is, heated in the presence of a process solvent that can stabilize as well as possibly activate the coal structure—then the coal can be liquefied to distillate products with a minimum use of molecular hydrogen. Basic nitrogen heterocycles seem to perform this function with surprising ease. As the coal is heated, the basic nitrogen heterocycles possibly hydrogen-bond with the coal structure, preventing retrogressive reactions by physically "capping" active sites that have been exposed by thermal disruption of O...HO hydrogen bonds. If nitrogen, a stronger hydrogen-bonding agent than oxygen, is not present during the heating, then condensation or polymerization will occur at the reactive sites, producing an intractable material. In addition, when liquefaction conditions are reached, the basic nitrogen solvents may activate the cracking and hydrogenation of the coal.

Coal moisture

As noted earlier, Gulf found that the drying of coal, even in an inert atmosphere, invariably resulted in a decrease in liquefaction conversion (RP779-25). It had been assumed that oxidation of the coal would cause a decrease in conversion, but the decrease with drying alone (without oxidation) was a surprising result. Although no chemical change in the coal appeared to have taken place, conversion was generally 10–20% lower when the coal moisture was not present. Thus a physical change had occurred.

The need for drying coal before liquefaction has been a foregone conclusion. Using coal with a high moisture content (25–30 wt%) would require a considerably larger reactor and, to maintain the necessary hydrogen partial pressure, excessive amounts of hydrogen gas. After the Gulf work, it was thought at first that either the decrease in conversion was an artifact resulting from the laboratory scale of the work, or if real, the decrease could be avoided by drying the coal in solvent. However, a liquefaction experiment at Mobil (RP1655) using a coal that had been dried in an excellent model solvent (30% tetralin, 70% pyrene) again showed a decrease in coal conversion. To confirm that some irreversible physical phenomena had occurred, Gulf dried coal in nitrogen and then put the moisture back. The liquefaction conversion was even worse than when the coal was dried and partially oxidized.

It appeared, then, that the alternative was either to run the coal as-received and accept the added costs of a larger reactor and increased hydrogen use, or to dry the coal and accept the decrease in conversion. The latest results on basic nitrogen compounds, however, indicate another option. Coal dried in a solvent containing basic nitrogen heterocycles has a conversion almost as good as the wet coal. The relationship between water and the basic nitrogen compounds appears to be extremely important. It is possible that water provides a transport mechanism for the basic nitrogen into the coal.

It is known that water is a superior solvent for ionic substances. One reason is that it contains the OH group and thus can form hydrogen bonds. (Water is generally a poor solvent for most organic compounds, but this can be overcome by adding another solvent such as methanol.) Perhaps, then, hydrogen bonding between the basic nitrogen heterocycles and water plays a role in incorporating the solvent into the coal structure. If so, as the water is driven off (212–300°F; 100–149°C), the basic nitrogen heterocycles may then act as spacers to prevent the coal structure from collapsing until hydrogenation occurs. The fact that the hydrogenated quinoline PY–THQ is somewhat soluble in water may provide the pathway into the coal. Coal that is permeated with moisture would sorb water-soluble compounds. Hydrogen bonding of basic nitrogen compounds (first with water, then with coal sites that had been hydrogen-bonded to water) would ensure that these potent hydrogen donors are available at the right sites when chemical reactions begin. If the water is first removed by drying, however, the coal may become less thermally stable. Then, when the coal starts to dissolve, the hydrocarbons may have aligned so that retrogressive reactions are favored.

Liquefaction results

Sufficient laboratory results on a variety of eastern and western coals are now available from Mobil (RP1655), the University of Wyoming (RP2110), Kerr-McGee Corp. (RP1715), and Virginia Polytechnic Institute (RP1696) to be able to state with confidence that the astonishing coal conversions achieved with solvents containing basic nitrogen compounds are not an anomaly of a certain procedure or laboratory.

With model basic nitrogen solvents, 100% conversion of coals (on a moisture- and ash-free basis) has been achieved. This means that the residue of the thermal reaction is pure ash: The carbon has been completely converted. Under very specific, controlled conditions, over 90% conversion of coal into distillate-type liquids can be achieved. Further, the reaction conditions required to accomplish these conversions are very mild.

Traditionally, only very low conversions were believed possible for western subbituminous coals (70–80% overall, 30–35% liquids). Although higher conversions had been achieved with eastern bituminous coals (95% overall, 50% liquids), they were also thought to have a maximum conversion. The research performed with the basic nitrogen solvents challenges these beliefs. The remarkable conversion results cited above (100% overall, over 90% liquids) were obtained with a low-sulfur, low-iron western subbituminous coal. For comparison, this coal was converted to only 55% liquids with the best process-derived solvent used to date, and more severe conditions were required.

The liquefaction research has produced many interesting results that support the hypotheses presented in this article:

- Improper drying causes irreversible damage to coal. All other conditions being equal, drying a western coal in nitrogen gas causes a 5–10% decrease in liquid yield.

- For both eastern and western coals, there is a significant increase in conversion when the liquefaction temperature is relatively mild—785°F (418°C), as opposed to the traditional temperatures of 840–850°F (449–454°C). A higher temperature does not result in any further increases in conversion for a western coal; incremental increases occur with an eastern coal.

- Western coal converts rapidly and completely to its final products. Although eastern coal converts rapidly to its initial products, conversion to the final products requires extended reaction time.

- Important basic nitrogen compounds can be process-derived and concentrated in the recycle solvent.

- If the liquefaction temperature is mild, 800°F (427°C) or less, virtually no gas is produced when basic nitrogen solvents are used.

- Soaking the coal under certain conditions in solvents containing basic nitrogen compounds radically improves conversion.

- Drying the coal in solvents containing basic nitrogen compounds does not significantly damage the coal.

- When a solvent with a high concentration of basic nitrogen compounds is used, a reaction time of 10–30 minutes and a temperature of 750–800°F (399–427°C) are adequate for high conversion to liquid products.

In addition to extensive work using model compounds such as quinoline and tetrahydroquinoline, work has also been performed with actual process-derived recycle solvents. The liquefaction behavior of these solvents always improves when the concentration of hydrogenated basic nitrogen compounds is increased. Preliminary indications are that there is a certain threshold level of these basic nitrogen compounds that must be reached and maintained in order to have a low-severity, high-conversion process. This is not an impossible goal. The chemistry of coal even appears to be helpful in attaining it. The affinity of the basic nitrogen compounds for the heaviest material with which they are in contact provides a means for their capture and control. *Heaviest,* however, may not necessarily mean highest molecular weight; nor does it refer to condensed, refractorized, polyaromatic, mistreated gunk. *Heaviest* most likely means the material most amenable to hydrogen bonding: undamaged monophenolics and other hydroxyl-type compounds. When hydrogen-bonded with themselves or the basic nitrogen compounds, these materials exhibit the physical characteristics of a high-molecular-weight material.

Several unusual observations have been presented here, and several explanations for them have been postulated. Process configurations based on this work are currently being explored. Proof of the validity of the observations and explanations, however, will only come when the research moves out of the laboratory to a continuous bench-scale liquefaction unit. This is the next step. *Project Managers: Linda Atherton and Conrad Kulik*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Director

FAN SYSTEM RELIABILITY

Fans and their related problems cause almost a 1% availability loss in large (over 400 MW) fossil fuel power plants and cost utilities over $100 million annually. Problems increase as boiler draft systems become more complex. EPRI has a seven-year, $4 million program to address a wide range of problems. Current work is on erosion control, failure analysis, noise control, foundation design, boiler draft system dynamics, and fan system guidelines. EPRI has made a failure-cause analysis of fan problems (CS-1693) and is studying root causes of failure mode contributions to fan unavailability (RP1649-6). Fan-originated dynamic effects also affect other plant components.

Fan erosion

Fly ash erosion is the major cause of fan problems. In coal-fired plants over 100 MW, erosion directly costs more than $12 million a year (CS-1596). Erosion caused 20% of all problems identified by the fan failure-cause analysis, mostly (15%) in induced-draft fans. Utilities reported that 34% of all induced-draft fans in coal-fired units currently require repair because of erosion, and in 14%, the damage was severe. Primary-air and flue gas recirculation fans also have erosion problems.

Fan erosion damage varies with fly ash erosivity, fan design, and fan materials. Removal of fly ash is the best defense against fan erosion, while blade armoring is the last defense.

A computer model has assessed the erosion resistance of various fan types and designs, and it can predict armor lifetime. One study suggests that a single-thickness backward-curved blade in a wide airfoil fan is preferable to one with either thick airfoil blades or a radial-tip wheel.

Laboratory tests show that traditional fan materials (steel, stainless steel, hardened steel) erode very quickly. Cobalt-based materials are two to six times more resistant, and chrome plate, high-chrome plate, and high-chrome iron have up to ten times more resistance. Advanced coatings (e.g., tungsten carbide applied with a detonation gun process) are up to twenty times more resistant (CS-1979).

Fly ash from bituminous coals is more erosive than that from subbituminous or lignite coals. Neither silica content nor the slagging and fouling indexes used by boiler manufacturers are a reliable indicator of fly ash erosivity. The crystalline material content measured by X-ray diffraction analysis may be a better indicator.

In general, control of fly ash erosion in fans can be achieved by the following.

- Proper fan selection based on predicted erosion rates
- Operating procedures to limit the fly ash bombarding the fan
- Armored fans that reduce maintenance and stay on-line between scheduled shutdowns
- Adequate precipitators for induced-draft fans to reduce fly ash concentrations to tolerable levels

Advanced armoring, such as chrome-plated shields or advanced coatings, is needed to extend fan life significantly within the weight limits of a fan wheel. Erosion problems at only 16 of 150 utilities surveyed would justify the cost of armoring, which is cost-effective only when erosion causes fan repair more frequently than during scheduled outages. EPRI is investigating means of fan erosion control, including field-replaceable armoring systems and erosion-resistant fan components and design (RP1649-4).

Noise control

Controlling and limiting sound from power plant fans and other equipment are increasingly important to electric utilities. The pure tone of the blade-passing frequency carries great distances from the plant. Fan noise is usually controlled by mufflers that reduce the blade-passing tone. These sounds originate in a concentrated region around the fan cutoff, where the impeller discharge interacts with the casing.

Other approaches to modifying the noise source are altering the cutoff clearance or configuration to change casing geometry, modifying the impeller design by staggering blade rows or by adding mesh to the inlet, and the novel method of replacing the cutoff with a resonator device. This last is simpler and more efficient than methods that change fan efficiency or those that work well at only one fan speed.

EPRI investigated a quarter-wavelength resonator whose perforated opening replaced a fan scroll cutoff (RP1649-7). A movable plug made the resonator frequency-sensitive (Figure 1). A resonator on a small fan (140 mm, 5.5 in) reduced the blade-passing tone by 28 dB and the overall sound pressure by up to 7 dB(A), without affecting the fan's aerodynamic performance. Work on a 235-mm (9.25-in) fan investigated the influence of the mouth area and configuration on sound absorption and on sound from the inlet and outlet ducts. Perforating the resonator mouth reduced sounds from either the inlet or the outlet; dividing the resonator tip interior by a splitter reduced the blade-passing sound from both ducts by 12–15 dB, the frequency of reduction depending on the load (Figure 2). The acoustic impedance of the resonator was not uniform within the tube and depended on flow near the cutoff. Resonators add little to the bulk of the machine and can be used for variable-speed fans if the length is modified with speed by adjusting the resonator plug.

EPRI has completed tests on a 160-cm (63-in) fan at the Buffalo Forge Co. test facility and is currently testing a 94-cm (37-in) airfoil fan at the EPRI–MIT test facility. A field demonstration is planned on a 318-cm

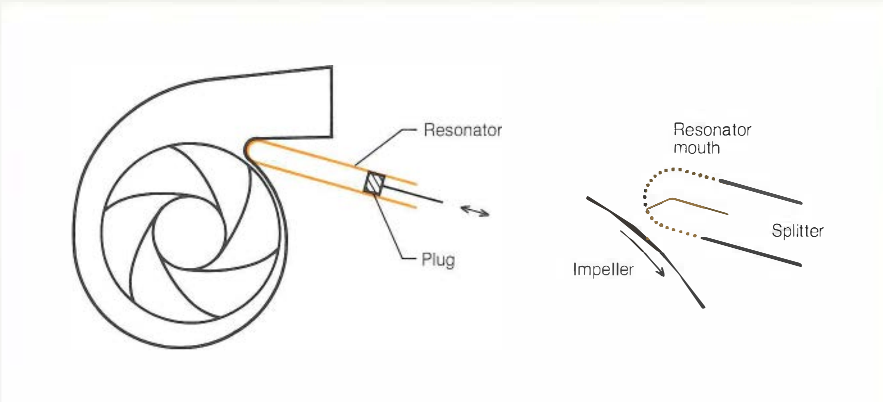


Figure 1 Centrifugal fan with quarter-wavelength resonator mounted at fan cutoff. Detail (right) shows resonator with splitter that reduces sound from both inlet and outlet ducts.

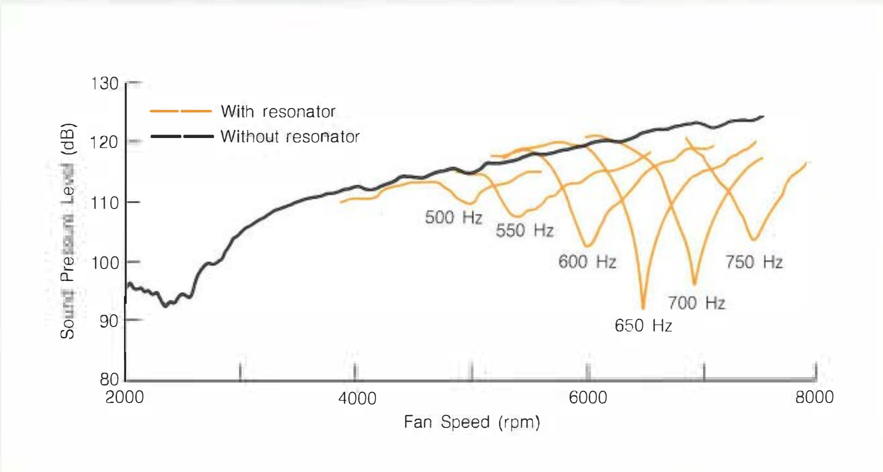


Figure 2 Level of the blade-passing frequency with and without a quarter-wavelength resonator tuned to different frequencies. Perforation, 37% open area; hole diameter, 3.8 mm; 38 holes.

(125-in) induced-draft fan at a member utility. Test results will be published in future EPRI reports.

Fan-foundation-soil system dynamics

Fan vibration problems are usually related to the entire system. But the dynamic characteristics are usually determined only for individual components, and a dynamic analysis of the total fan-foundation-soil system is rare. The utility industry not only uses different definitions of critical speed and other factors but also omits the dynamic characteristics of the foundation and supporting soil. Hence, there is no requirement in fan specifications that the integrated fan-foundation-soil system dynamic characteristics avoid resonances.

A computer-based model has been developed to evaluate the dynamic performance of integrated fan-foundation-soil systems (FP-864) and applied to the analysis of fans at seven utilities: two primary-air fan-foundation-soil systems and five large induced-draft fan-foundation-soil systems. Reasonable agreement was achieved between the analyses and corresponding field tests (CS-1440).

The model is a state-of-the-art advance in fan dynamic analysis. It includes supporting soil; foundation; pedestals; bearings; fan housing, rotor, and wheel; drive motor; and any other important components affecting system dynamic characteristics. The analytic model of a typical integrated system has more than 100 associated degrees of freedom. The model computer code (FAN) is available at EPRI's Electric Power Software Center. Two significant conclusions resulted from this investigation.

□ The stiffest rotor may not provide the best dynamic response. The fundamental frequency of the system is often below the rotor operating speed (low-tuned) because of the foundation and soil. Specifying that the rotor's first critical speed be above the operating speed (high-tuned) is thus offset by the low-tuned system.

□ A large foundation may be more sensitive and vibration-prone than a small one. In general, the foundation design should be based on a dynamic analysis of the specific integrated system and optimized on the basis of cost.

The investigations gave additional insight into appropriate ranges for system parameters, especially soil stiffness and bearing damping. Soil damping includes both internal dissipation and wave propagation. Bearing oil film stiffness and damping coefficients may deviate significantly (up to 400%) from values provided by manufacturers, and deviations can have substantial dynamic ramifications. Additional research is needed on soil properties and on bearing characteristics.

It may be desirable to specify fan systems to be low-tuned because the shaft may be lighter and the rotor lower in cost than those in a high-tuned unit. EPRI will modify an existing fan that operates near its critical speed to a low-tuned rotor with a first critical speed between 0.8 and 0.9 times the operating speed.

This work is continuing to develop guidelines on fan-foundation-soil systems for the utility industry (RP1649-3). EPRI is cooperating with six member utilities to design fan systems with this approach.

Boiler draft system gas dynamics

Large-amplitude, low-frequency pressure pulsations in combustion air, flue gas, and recirculation gas systems have caused severe or catastrophic damage to equipment at several fossil fuel plants. The effects of these disturbances included failures of induced-draft or flue gas recirculation fans, excessive fan vibrations, and fatigue failure of mechanical structures and components (e.g., ducts, brackets, and bearings).

EPRI is investigating such problems through a three-phase research program (RP1651). During Phase 1, a computer-based model was developed to study the dynamics of air-gas systems. The model represents all types of boiler draft systems: combustion air systems, including forced-draft fans, air preheater, ductwork to furnace; flue gas systems, including induced-draft fans, air preheater, precipitators, scrubbers, ductwork to stack; and flue gas recirculation fan and duct. Major plant elements are represented: plenum volumes, flow resistances, wave propagators, and the fan. Elements are assembled to represent any boiler draft dynamic system. The laboratory test facility and both power plants used for field tests were well represented by the model (CS-1444, Vols. 1 and 2).

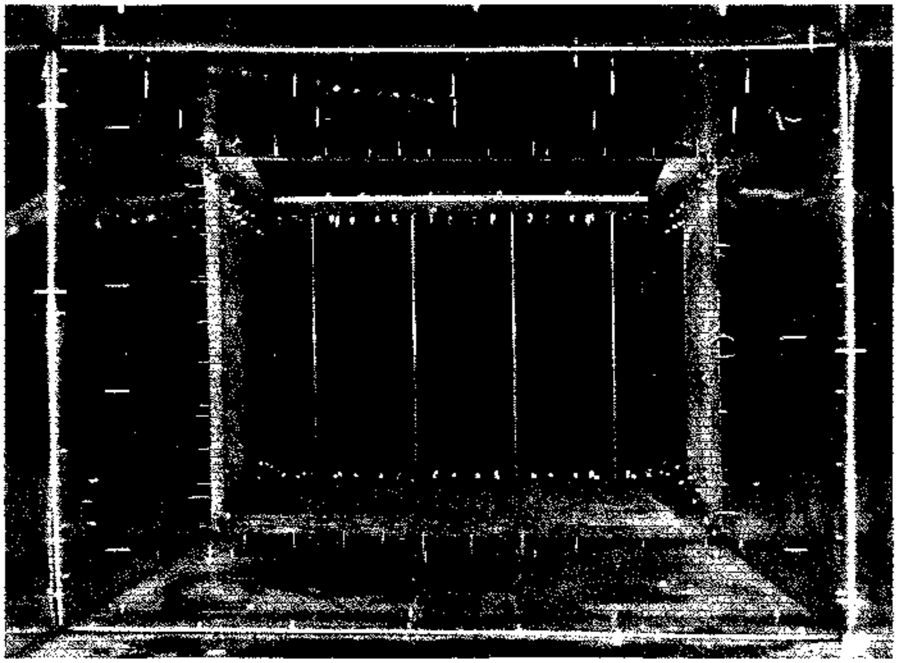
During Phase 2, solutions to dynamic problems were identified and evaluated, and both passive and active damping systems were assessed. Jet flap dampers were identified as promising devices to control aerodynamic disturbances and negative-pressure transients in boiler draft systems. A basis is being developed for selecting boiler draft system components to avoid dynamic problems.

Significant disturbances were found at the frequency of a rotating stall cell in the centrifugal fan and its first harmonic, corresponding to two-thirds and four-thirds fan rotation speed. The stall limit line of the fan characteristic was shown to be very close to the maximum efficiency region of the fan. A small perturbation could cause the fan to stall and create significantly increased pressure disturbances. Designs, operating methods, and control strategies should be developed to permit fan operation near peak efficiency and avoid stall (CS-1444, Vol. 5).

Data were gathered on boiler draft systems at two utility plants: a 125-MW unit and a 500-MW unit. Both units had low-frequency oscillations at air preheater rotation speed and higher-frequency disturbances from forced-draft, induced-draft, and flue gas recirculation fans. In the 125-MW plant, the air preheater disturbance was 1–2 in of water. Air preheater disturbances in the 500-MW plant were only 0.2 to 0.5 in of water because the air preheater had been recently cleaned. These disturbances normally can be reduced by fan inlet vanes. Large and less controllable pulses can occur as the preheater passages become clogged. Important effects on furnace pressure controls, the combustion process, and fan stall can result. The furnace volume isolates frequencies above 1 Hz, and there is very little coupling between the forced-draft system, induced-draft system, and flue gas recirculation system.

The flue gas recirculation ducts had relatively high levels of pressure spectra at fan rotational frequency and harmonics. Significant peaks at two-thirds and four-thirds times the fundamental were attributed to rotating stall. In the 500-MW plant, a strong spectral component at the ductwork natural frequency arose when the inlet dampers were below 40% and caused high levels of vibration (CS-1444, Vol. 3). The displacements decreased to a quarter of the initial value when the damper setting was increased from 25% to 40% (Figure 3).

Figure 3 Jet flap dampers installed in a 3.5 × 3.5-ft test duct.



During Phase 3, the computer model was modified to simulate the air and gas pressure excursions that follow a main fuel trip. The large EPRI–MIT boiler gas dynamics experimental facility was built during this phase, and jet flap dampers are being tested to determine whether jet flaps can control continuous pressure pulsations and prevent dangerous negative transient boiler pressure excursions (implosions) that can follow a main fuel trip.

The model also simulated various experiments, including the transient response at one plant to a maximum-rate ramped opening of the gas recirculation fan dampers. The model achieved a good representation of rotational and stall disturbances and broadband fan noise for both units. Further refinements of the model incorporate extensive test results from both a laboratory system and a power plant, enabling it to simulate the dynamic transients (including boiler implosions) that result from flameouts. The complete code (AGDOPP) is available at the Electric Power Software Center.

Fan testing

The electric utility industry needs but does not have a generally accepted test procedure to determine the as-installed performance of large fans for fossil fuel power plants. The size and power requirements of these fans make them virtually impossible to test in a laboratory. Conversely, the generally unfavorable configuration of the ductwork at a power plant makes accurate field testing very difficult.

For several years, the ASME Performance Test Code Committee 11 (PTC-11) has been developing such a procedure. EPRI has supported field tests of two fans to verify the procedure proposed by PTC-11 and to investigate certain velocity probes and electronic instrumentation for use under field conditions (CS-1651). The field tests advanced the development of the test code, provided an opportunity to the PTC-11 members to verify the test procedures, investigated use of a two-angle velocity probe, and compared time-averaging of pressures by liquid manometers with electronic instrumentation averaging.

Seven tests were performed at an operating 650-MW coal-fired unit, four on a forced-draft fan and three on an induced-draft fan. Flow variables (static pressure, velocity components, temperature, gas composition) were measured at a grid of locations centered on small areas (less than 2 ft^2). Traverses were in planes close to the inlet and discharge of each fan. All instrumentation was standard, except for a specially built five-hole, two-direction probe to measure both pitch and yaw angles.

Other code measurements were standard: input power measured by the prime mover or a torque meter; speed by a revolution counter; temperature by a thermocouple on the probe; and gas composition by an Orsat device or electronic analyzer. Fluid properties are derived from measured quantities.

A computer program developed to reduce data consistent with the PTC-11 test code (FANTEST) is available at the Electric Power Software Center. The PTC-11 method has also been compared directly with tests performed in accordance with the fan manufacturer's (AMCA) test code. Independent tests have been made at both a manufacturer's test facility and the EPRI–MIT test facility. Results from these tests will be available in the near future.

Pending results from RP1649-6, EPRI plans to initiate work on fan vibration and bearings. In addition to the technical reports from these and other fan projects, EPRI will issue fan design, procurement, and acceptance guides for utility use that cover a variety of related topics: components, materials, noise attenuation and control, aerodynamics of integrated fan-draft systems, and nondestructive and performance testing (RP1649-8). *Project Manager: Isidro A. Diaz-Tous*

MATERIALS FOR FGD SYSTEMS

Corrosion and erosion of construction materials represent a major cause of the high costs and poor reliability associated with flue gas desulfurization (FGD) systems. EPRI has initiated a program to evaluate candidate materials for lime/limestone systems. The program entails a determination of the state of the art of materials selection for FGD systems, laboratory evaluations of alloys and coatings in simulated scrubber environments, and field evaluations of promising coatings and alloys. In the initial project of this program, literature on the behavior of construction materials commonly used in FGD systems has been critically reviewed, and laboratory evaluations of alloys and coatings in simulated outlet duct environments have been performed (RP1871).

Literature review

The objectives of the literature review were to identify failure modes for alloys and coatings in various components of lime/limestone FGD systems; to identify the important parameters that influence the corrosion behavior of these materials; and to explain the effects of these parameters in order to aid in system design and materials selection. The following is a brief summary of the review's findings and their relevance for the corrosion problems experienced in FGD systems.

Materials now commonly used, or being considered for use, in lime/limestone FGD systems are austenitic stainless steels, nickel-base alloys, ferritic and duplex stainless steels, titanium, and organic and inorganic linings.

The literature indicates that austenitic stainless steels (types 304, 316, 317, and 904) are susceptible to several failure modes in acid-chloride environments like those of lime/limestone scrubbers. These modes include pitting and crevice corrosion, transgranular stress corrosion cracking (TGSCC), intergranular stress corrosion, intergranular stress corrosion cracking (IGSCC), and erosion-corrosion. The degree of susceptibility is dependent both on the material and on environmental parameters.

The carbon content of austenitic stainless steels has a major influence on their sensitization and resulting susceptibility to intergranular corrosion and IGSCC; it also affects their susceptibility to pitting and crevice corrosion. Because of the severity of the intergranular attack, special low-carbon-grade stainless steels (e.g., types 316L and 317L) are often used. The carbon content of these alloys is reduced to below 0.03%. Also, titanium and niobium are added to stabilize carbides and obtain more resistant alloys—for example, type 321 (with titanium) and type 347 (with niobium). However, these elements also induce the formation of intermetallic compounds, such as σ phase, which are also susceptible to attack in certain environments.

Molybdenum and, to a lesser degree, chromium and nickel have proved to be beneficial in increasing resistance to pitting and crevice corrosion. Molybdenum is an essential alloy addition for most scrubber applications. In contrast, manganese and sulfur have a detrimental effect on the pitting resistance of the 300-series stainless steels.

Nickel influences resistance to TGSCC. Maximum susceptibility is found at nickel concentrations of 10%; greater concentrations significantly increase resistance to TGSCC. In general, nickel also increases resistance to erosion-corrosion, which is evident in comparing nickel-base alloys with stainless steels.

There is much evidence that certain environmental variables—for example, chloride concentration, oxygen concentration, temperature, and pH—have significant effects on the corrosion behavior of austenitic stainless steels. The effects of chlorides and pH are of particular importance because materials are often subjected to high chloride concentrations and low pH in typical scrubber environments. Reheater tubes are especially susceptible to stress corrosion cracking because of the higher temperatures they experience and the likelihood of residual stresses from fabrication and thermal expansion. TGSCC rarely occurs below 60°C and thus is not likely to be a problem in most scrubber components.

The literature indicates that while nickel-base alloys are susceptible to corrosion-related failures in environments like those encountered in scrubbers, they are generally much more resistant to attack than austenitic stainless steels. This resistance can be attributed to the fact that they contain greater amounts of certain alloying metals. Chromium and molybdenum improve resistance to pitting and crevice corrosion, while nickel improves resistance to TGSCC.

The ferritic and duplex stainless steels are much more resistant to TGSCC than austenitic stainless steels and nickel-base alloys. However, they are especially sensitive to improper heat treatment and welding, which limits their application in field-fabricated components of FGD systems. Improper heat treatment increases susceptibility to intergranular corrosion. Sensitization in these alloys can be decreased by reducing their combined carbon and nitrogen content to less than 0.01%.

Titanium and titanium alloys are highly resistant to all forms of corrosion in aqueous chloride solutions, including those with very high chloride concentrations. Minute amounts (<1 ppm) of fluoride ions can seriously affect the corrosion resistance of titanium, however, by dissolving the protective oxide film that normally forms on the material. This is important when considering scrubber environments that may contain soluble fluorides.

As documented in the literature, coated carbon steel has been used extensively in scrubbers as an alternative to costly high-alloy materials. Coating materials include vinyl esters, epoxies, polyesters, fluoroelastomers, brick, monolithic ceramic linings, and rubbers.

Rubbers, vinyl esters, epoxies, and polyesters have been successfuly used in relatively mild environments, such as that of the absorber. These organic linings can generally withstand low pH and high chloride concentrations but are vulnerable to thermal changes. Fluoroelastomer linings have been developed for higher-temperature applications (to 200°C) where good acid and chloride resistance is required, such as in outlet ducts and stacks. Ceramic linings, brick or monolithic, are also used at temperatures above 175°C and in wet areas where abrasive materials are entrained in the gas stream. These conditions are common in gas inlet ducts, venturis, scrubbers, outlet ducts, and stacks. The major problem associated with nonmetallic linings has been debonding, which is thought to result from penetration of the lining material by liquids. This is usually blamed on poor application and/or poor surface preparation.

The literature provides a good deal of information on specific FGD system applications of various alloys and linings. Field experience and exposure tests indicate that carbon steel and low-alloy steels have extremely high corrosion rates in prescrubber environments, where the pH of the liquid is generally less than 2 and the chloride concentration is high (>5000 ppm). Extensive pitting has been observed on stainless steels and even Inconel 625. The most resistant materials in this region have been Hastelloy G (nickel base), AL 6X (iron base), and titanium. However, these materials have also suffered attack by erosion. One case of high corrosion rates for titanium was reported, an effect attributed to the presence of fluorides in the flue gas.

Linings have been used to control erosion-corrosion and pitting of carbon steel in the prescrubber region. The most successful has been brick backed by a corrosion-resistant membrane (usually lead, rubber, or plastic) and supported by a carbon steel structure.

Both lined carbon steel and stainless steels have been used in absorbers for FGD systems. Type-316 and type-317 stainless steels have demonstrated good corrosion behavior when pH ranges from 4 to 6 and the chloride concentration is less than 1000 ppm. In closed water loop systems, which are becoming more common in new designs, the chloride concentration is increased significantly; unless chlorides are removed in a separate prescrubber loop, these systems require the use of more resistant materials.

Because of lower initial investment costs, many different lining materials have been used in absorbers, and the results have been good. In particular, rubber linings on carbon steel, both at the absorber walls and in areas with abrasive conditions, have achieved over 10,000 hours of operation without failure.

Outlet ducts, however, have a significant history of materials problems necessitating lengthy boiler repair outages. The outlet flue gas upstream of a reheater creates an extremely corrosive environment (having a pH of less than 2 and containing chlorides). Only titanium, the iron-base alloy AL 6X, and the nickel-base alloys Hastelloy C-4, Hastelloy C-276, Inconel 625, and Hastelloy G have performed well in the most aggressive environments. This situation can be aggravated when bypass reheat is used and there is significant mixing of moisture carry-over from the absorber.

The ducts downstream of the reheater experience lower corrosion rates if the flue gas is above its saturation temperature. If it is not, however, or if there is insufficient gas-mixing to achieve uniform temperatures, then reheating can actually increase corrosion rates. Because it is seldom possible to ensure enough residence time to completely evaporate entrained droplets in gas streams, some corrosion protection is required downstream of a reheater.

Laboratory evaluations

Laboratory experiments were carried out to evaluate the performance of alloys and linings for use in the outlet ducts of lime/limestone scrubbers. The resistance of alloys to pitting and crevice corrosion, stress corrosion cracking, and intergranular corrosion was evaluated by exposing stressed U-bend specimens to simulated duct environments. These specimens contained welds oriented longitudinally across the apex of the U-bend (Figure 4).

The resistance of the linings to the test environments was evaluated by hardness measurements. To study how damage to the lining affects adhesion between the lining and the carbon steel substrate, grooves were machined in the linings before exposure.

Two duct environments were simulated by an acid mist containing sulfurous acid and calcium chloride (200 ppm Cl^-). In one environment, sulfuric acid was added to adjust the pH to 1; in the other environment, hydrochloric acid was added to achieve the same pH while increasing the chloride concentration to 5000 ppm. The temperature was held at 120°F (49°C). The oxygen concentration in the mist was approximately 8%, which was achieved by sparging with an appropriate mixture of air and nitrogen gas. Periodically, specimens were removed from the wet acid environment and placed in hot

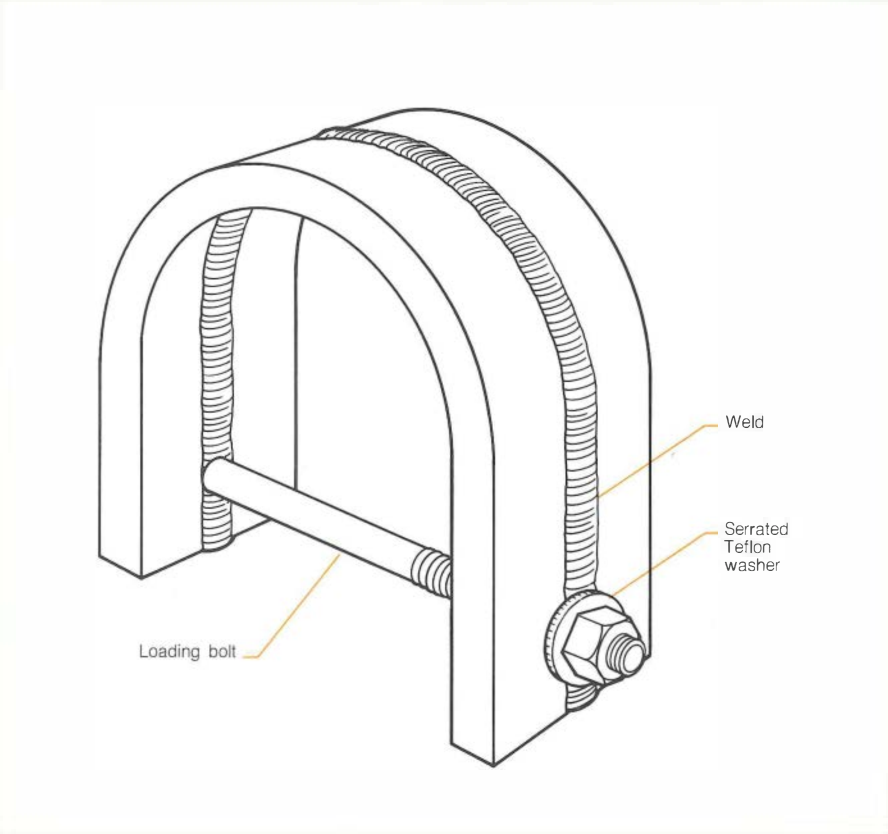


Figure 4 Welded and stressed U-bend specimens like this were exposed to simulated FGD system outlet duct environments to evaluate the resistance of various alloys to pitting and crevice corrosion, intergranular corrosion, and stress corrosion cracking. Stress is provided by the loading bolt, and artificial crevices by the serrated washer.

dry gas—250°F (121°C), 8% oxygen—to simulate upset conditions.

At a chloride concentration of 200 ppm, all the alloys tested were resistant to both localized attack (intergranular corrosion, pitting, and crevice corrosion) and uniform attack. At a chloride concentration of 5000 ppm, however, the 300-series stainless steels showed considerable pitting and crevice corrosion (Table 1). Also, some of these alloys suffered high uniform corrosion rates, as indicated by the weight loss results in the table. The austenitic stainless steel 904L showed severe pitting and crevice corrosion. The duplex stainless steel Ferralium also suffered considerable pitting and crevice corrosion, as well as intergranular corrosion.

The nickel-base alloys Hastelloy C-276, Hastelloy G, and Inconel 625 and the iron-base alloy AL 6X appeared to be resistant to localized and uniform attack. Moderate weight loss was measured in Inconel 625. Both commercial-grade titanium alloys were highly resistant to attack in the simulated duct environments.

A significant observation was the high resistance to pitting and uniform corrosion of the ferritic stainless steel Monit. However, crevice corrosion and intergranular corrosion in the weld were observed. It is possible that this alloy's susceptibility to intergranular corrosion could be decreased by limiting its combined carbon and nitrogen content to less than 0.01%. If so, the alloy might represent a cost-effective alternative to the more expensive nickel-base and titanium alloys.

The following lining materials were investigated: natural rubber (Goodyear LS551), neoprene rubber (Goodyear LS575), spray-on vinyl esters (Plasite 4004-5 and 4005), glass-flake-reinforced polyester (Flakeline 103), glass-flake-reinforced vinyl esters (Flakeline 100 and 180), phenolics (Phenoline 373 and Carboline L8500-1), and a chemically bonded silicate cement (Carboline). In general, these materials were resistant to the wet acid environments, even when the chloride concentration was 5000 ppm. Only the polyester lining Flakeline 103 showed a significant decrease in hardness. However, none of the linings tested had sufficient resistance to temperature upsets. Some linings, most notably the fluoroelastomers, have been developed that appear to be capable of withstanding temperatures up to 200°C. Although these were not tested in the present study, they are included in other EPRI research on scrubber materials.

In conclusion, only the nickel-base alloy Hastelloy C-276 and the Grade 2 and Grade 12 titanium alloys can be considered corrosion-resistant construction materials for scrubber outlet ducts under conditions like those used in this experimental study. Inconel 625, Hastelloy G, AL 6X, and Monit may also be considered if some corrosion attack is acceptable. In particular, Monit could be a reasonably economical alternative if problems associated with intergranular attack of the weld and TGSCC could be alleviated through changes in alloy composition.

The results summarized above must be applied with caution. There are major difficulties in relating these experimental data to actual field operation, in part because of a lack of knowledge about actual scrubber duct environments. Moreover, the actual range of parameters studied was not broad enough to encompass all possible service conditions. Nor were all the environmental variables that may influence performance included. For example, the presence of other halides—such as fluorides and bromides, concentrations of which have only recently been measured in operating systems—may significantly degrade the performance of certain materials. *Project Manager: Charles Dene*

Table 1
ALLOY PITTING AND WEIGHT LOSS IN A SIMULATED HIGH-CHLORIDE SCRUBBER ENVIRONMENT

	Maximum Pit Depth (μm)		Weight Loss (%)	
Alloy	Continuous	Alternate	Continuous	Alternate
Nickel-base alloys				
Hastelloy C-276	Negligible	Negligible	0.019	0.027
Hastelloy G	<10	<10	0.339	0.250
Inconel 625	14	13	0.496	0.444
AL 6X (iron base)	Negligible	Negligible	0.475	0.400
Austenitic stainless steels				
Type 904L	304	128	0.885	0.640
Type 317LM	109	176 (weld)	0.509	0.440
Type 317L	384	292 (weld)	0.546	0.410
Type 316LM	372	319	1.600	1.048
Type 316L	152	298	0.800	0.573
Monit (ferritic stainless steel)	72	68	0.318	0.230
Ferralium (duplex stainless steel)	106	82	0.934	0.800
Titanium Grade 2	Negligible	Negligible	0.004	0.024
Titanium Grade 12	Negligible	Negligible	0.009	0.025

Note: *Continuous* indicates continuous exposure to a moist acid environment with a pH of 1 and a chloride concentration of 5000 ppm; *alternate* indicates alternate exposure to the moist acid environment and a hot dry environment. Each maximum pit depth value is the average of five measurements.

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

DISTRIBUTION

Communication systems for distribution automation and load management

Both the reliability and the efficiency of electric power distribution can be increased with improved load management, of which one aspect is distribution automation. Distribution automation, as used in this context, includes all communication and control functions for the distribution system, such as load control, time-of-day metering, remote meter reading, feeder switching, capacitor bank control, transformer temperature monitoring, and fault location and isolation. The central requirement for distribution automation and load management is a complete, versatile, and cost-effective two-way communication system.

EPRI and DOE have completed a jointly sponsored research program to develop and test two-way communication systems intended for use with load management and distribution automation (RP850). The performance of these systems has been evaluated by host utilities to establish the capabilities and limitations of each communication system.

When this program began in 1976, three communication technologies were chosen: power line carrier (PLC), radio, and telephone. Each of these technologies has advantages and disadvantages.

A PLC system's advantages are complete coverage of the entire electrical system and complete control by the utility. Its disadvantage is that additional equipment must be added to the distribution system to condition it for communication purposes. A further disadvantage is that under mass failure or damage to the distribution system, the communication system could also fail. In other words, if the poles are down, the communication system may fail, preventing the feeder-sectionalizing necessary for restoration of service.

The advantage of a radio system is that it could be owned and operated by the utility. It is a communication system separate and independent of the status of the distribution system. It can also be operated at the highest data rate of the three technologies. The main disadvantage of the radio system is that the signal path can be blocked.

A telephone carrier system has the potential advantage of being the least expensive because it exists as a communication system in most homes and businesses; however, existing tariffs probably make the telephone system one of the more expensive concepts at this time. Its disadvantages are that not all meters have telephone service at or near them, and the utility does not have complete control of the telephone system (which could be a problem during emergencies).

The intent of this research was to test communication and control systems that can satisfy every conceivable application for distribution automation. Five systems have been implemented, each by a selected manufacturer-utility team (Table 1). The manufacturers developed and installed the systems; the utilities operated, tested, and evaluated the systems for approximately one year. Each system provided two-way communication to approximately 700 customer meters and 50 distribution control points. For the three PLC systems, two substations were used; both overhead and underground feeders were included. The systems included urban, suburban, and rural feeders ranging from 1 to 30 km in order to test the system performance in industrial, commercial, and residential environments.

In spite of significant delays caused by initial hardware and software failures, the communication systems were eventually improved to a respectable level of performance. In fact, the systems tested logged a total of over 2,000,000 two-way communication operations.

The two-way communication performance of the three power line carrier systems—American Science and Engineering, Inc.; Brown Boveri Compugard Corp.; and Westinghouse Electric Corp.—ranged from a success rate of less than 50% to over 80% during the year of test and evaluation. Nevertheless, these projects demonstrated that two-way PLC communications for distribution automation are possible. Improvements in equipment design needed for commercial

Table 1
MANUFACTURER–UTILITY TEAMS

Manufacturer	Utility	System	Sponsor
American Science and Engineering, Inc.	San Diego Gas & Electric Co.	Power line carrier	DOE
Brown Boveri Compugard Corp.	Carolina Power & Light Co.	Power line carrier	EPRI
Westinghouse Electric Corp.	Detroit Edison Co.	Power line carrier	EPRI
Westinghouse Electric Corp.	Long Island Lighting Co.	Radio	EPRI
Harris-Darcom, Inc.	Omaha Public Power District Metropolitan Utilities District Northwestern Bell Telephone Co.	Telephone	DOE

systems have already been initiated by the manufacturers. Detailed information about the EPRI-sponsored work is contained in the final report EL-1860, Volumes 1–4, which can be obtained from the Research Reports Center.

The two-way communication performance of the UHF radio system exceeded the 88% level. This radio system, however, did suffer an unacceptable number of hardware failures because prototype UHF radios were used in this project. The project proved that adequate two-way communications were possible over a variety of environmental and operational conditions.

The two-way communication performance of the telephone systems exceeded the 95% level, and equipment failures were minimal. However, both the voluntary participation of the telephone companies and the tariff rates they would charge utilities for digital communications are unresolved. Firm agreements for present and future costs of service must be made between electric utilities and the telephone companies.

As a final comment on the EPRI–DOE program, the state of the art of all three communication technologies has been advanced, and the manufacturers have moved closer to developing commercial systems that will satisfy utility requirements for distribution automation. If these systems can also be made cost-effective, most utilities would benefit by their application.

If utilities choose PLC, they will need to develop a better understanding of the characteristics of their own distribution circuits. Studies of the circuit characteristics causing the standing-wave problem are needed, together with the development of ways to avoid or overcome it. Precise inventories of installed equipment, especially capacitor banks, transformers, and switchgear, are necessary. Noise sources within the distribution network must be identified, and methods for detecting and eliminating (or at least, controlling) these sources must be developed.

EPRI and DOE have jointly published a series of reports for various levels of reader interest: an executive summary presents an overview for utility executives and public utility commissions; a program final report summarizes the results of the five projects for utility and manufacturer managers; and final reports for each of the five projects provide data for utility and manufacturer engineers. These reports are available from EPRI and DOE for their respective projects.

The Westinghouse–Detroit Edison Co. PLC system was sufficiently successful for EPRI to fund a two-year follow-on project, the object of which is to verify that improvements in equipment and systems mentioned above will satisfy utility requirements for distribution automation. *Project Manager: William Blair*

Reliability and risk assessment models

Although both utilities and the public are aware of and enjoy excellent service, it is difficult to compare present-day service with service conditions of 20 years ago because distribution systems, unlike transmission and generation, have suffered from the lack of adequate, consistent, and timely performance data. Few records that quantified service reliability were kept before 1950, and since then, both energy applications and energy requirements have changed dramatically.

Now, however, utilities recognize the importance of obtaining historical data to predict the future, and they spend considerable time, effort, and money monitoring system performance as an after-the-fact activity. The data obtained can serve as a means to analyze what went wrong (and correct it) and as a tool to predict and control future service reliability; neither can be done, however, without the proper formatting and modeling of the data so that one can assess past performance and predict future activities efficiently. Hence, in 1977 EPRI funded a project to develop improved methods to analyze historical performance and to predict reliability of future systems on the basis of data commonly obtained from distribution systems (RP1356). In this project, system reliability was examined from two perspectives: historical and predictive. Methods of assessing historical reliability were analyzed to develop a general outage reporting scheme that would be suitable for a wide variety of distributing utilities. By contrast, predictive assessment methods were examined in terms of risk taking—that is, the consequences of implementing or not implementing certain system reinforcement strategies.

These reliability assessment methods were ultimately developed and coded into computer models: a historical assessment model (HISRAM) and a predictive assessment model (PRAM).

HISRAM focuses on the input requirements for each of four levels of data analysis. The first of HISRAM's four levels is simply an incident log that would limit the utility to system reliability indexes. Level 2 allows greater resolution than Level 1 because the reliability indexes are calculated for subdivisions, and emphasis is placed on the factors that contribute to lack of reliability. Level 3 includes the collection of component outage data in sufficient detail to produce a realistic risk model. Level 4 adds the modeling of improper operation of protective devices.

The multilevel reporting system is designed in modules so that only the data required to support the desired level of analysis must be collected. This multilevel approach allows a utility to start out with a basic reporting scheme and advance to the more sophisticated schemes simply by increasing the data input to the program. The output reports of this program are formatted to display the analyzed data in terms of the standard EEI systems performance indexes.

The aim of the predictive reliability model, PRAM, is to enable a utility to estimate the reliability of a specific location on its system. It employs component reliability indexes calculated by HISRAM to predict system performance; it then provides a means to compare the predicted performance with alternative system reinforcement strategies. In addition, PRAM has been incorporated into a previously developed distribution feeder planning model, which was the output of another EPRI project (RP570).

The development of these reliability and risk models will add another dimension to the distribution planner's repertoire of planning tools. The distribution planner will now be able to evaluate the performance of the various alternatives being considered and calculate risks associated with postponing any system reinforcement. However, it should be emphasized that PRAM should be viewed as a planning tool and not as a model that will duplicate actual system performance.

A handbook of reliability assessment methods has been compiled and is available as a separate, stand-alone volume from the final reports for this project. Both computer programs have been successfully tested and executed by two participating utilities: Duquesne Light Co. and the Public Service Electric and Gas Co. (New Jersey). The handbook (EL-18-16-LD) and final reports (EL-2018) are available from the Research Reports Center. The computer programs for HISRAM and PRAM are available from the Electric Power Software Center. *Program Manager: William E. Shula*

OVERHEAD TRANSMISSION

Compact transmission line flashover

Phase-to-Phase Switching Surge Design (EL-1550) reported on the tests of phase-to-phase flashovers for spacings of 3–12 ft (0.9–3.6 m), and thus the results might only apply to systems up to 138 kV. As it is quite feasible to consider compact transmission line designs up through a 500-kV rating, it was decided to expand the study to 24-ft (7.3-m) spacings and to vary a number of other parameters, such as bundled conductors and time-to-crest of the switching surge (RP1492).

A second reason for expanding the study was that the weather model (i.e., flashover as a function of weather parameters) proposed in EL-1550 could not be supported by flashover theories. It is certainly true that the proposed weather model could not be applied to conditions different from those of the test site.

For these reasons, this new project was undertaken to supplement EL-1550. The project was divided into four segments: physical theoretical modeling, transient network analyzer (TNA) studies, phase-to-phase flashover testing, and statistical analysis.

The contractor, Power Technologies, Inc. (PTI), secured the services of Werner Busch, a theoretical physicist who is an expert on the physics of flashover. He developed a theoretical model of the phase-to-phase flashover process with which all test results and statistical analyses will be compared. This portion of the work is complete. During a workshop in December 1981, a small group of experts from several U.S. and Canadian companies reviewed and commented on the model. Basically, this group of experts accepted the model as being consistent with current knowledge.

The second step was to analyze a large amount of TNA data to determine which parameters describing phase-to-phase switching surge are important and to determine the significant ranges of these parameters. This knowledge made it possible to design the tests to investigate realistic field conditions.

The third and most time-consuming segment was to conduct full-scale laboratory tests on a prototype line. The 450-ft (137-m) span was erected at the Westinghouse high-voltage laboratory in Trafford, Pennsylvania. Some 10,000 test shots were taken over a period of six months and spanned parts of three seasons. Shots were made every 45 seconds during the working day for a particular sequence and recorded on magnetic tape for later computer analysis. Some tests were made at night, and time-lapse photographs were taken to help confirm the theoretical model. The testing is complete, and the project is entering its final segment.

Data from this project are being combined with data from EL-1550 so that a consistent analysis over the whole span of variables can be made at one time. The total number of shots to be analyzed approaches 18,000. Sophisticated computer programs have been written so that data from all the tests can be analyzed at one time to determine the cumulative effects of many variables.

It is expected that the result of this project will be a design methodology that can be used by utility line designers to accurately predict the phase-to-phase switching surge performance for any line that has phase spacing of 3–24 ft (0.9–7.3 m). This information should be valuable as new, cost-effective compact lines are designed to meet cost and environmental constraints. *Program Manager: Richard Kennon*

TRANSMISSION SUBSTATIONS

Generator circuit breaker development

As generators have increased in size, the station equipment requirements to provide the desired operating flexibility and necessary equipment protection have become costly. The large current-carrying components at generator voltages have made equipment such as the generator breaker very expensive. Because of this, the generator is often connected directly to its step-up transformer, and all switching is done on the high-voltage side of the transformer. This arrangement results in lower station costs but increases the complexity of the station service power supply system, including its operation during plant startup and shutdown. By contrast, today's nuclear power plant has a need for two off-site auxiliary power supplies for reliability, and the switching equipment arrangements to meet these requirements can usually best be satisfied by using generator breakers.

At this time large generator breakers are of the compressed-air type, but if generator ratings continue to increase, the extension of that breaker technology would be expensive and the product costly. Because generator ratings can be expected to continue to be used, EPRI let a contract to Gould–Brown Boveri, Inc. to study rating requirements of large generator circuit breakers and breaker design concepts to meet those requirements (RP1501).

There are no existing industry standards covering the rating structure for generator circuit breakers. While these were being formulated, it was necessary (as a part of this project) to study how the type of fault and its location affected the characteristics of generator fault currents and transient recovery voltages following fault current interruption. The IEEE Working Group developing generator breaker standards provided assistance in establishing the parameters to be used in these studies. The basic rating targeted for design consideration now includes a continuous current rating of 48 kA and an interrupting rating of 350 kA symmetrical at 38 kV.

The results of literature surveys showed that a generator breaker should be able to force current zero for early interruption of faults occurring under some operating conditions. This requirement was confirmed by a detailed study that the American Electric Power Co., Inc., made for one of its applications, the results of which were shared with EPRI.

Circuit breaker technology was then reviewed to determine the approach that would best meet the requirements of large circuit breakers. These studies showed that it would be desirable to have a breaker with current-limiting ability. Several breaker concepts were then developed that included a current-limiting element in series with a relatively low-duty interrupter. The interrupter would be capable of performing all normal generator switching operations, as well as clearing the fault current let-through during short-circuit interruption.

Two concepts were developed. In one, the current-limiting element would be a frangible (detonation-segmented) conductor, and in the other, a liquid metal, variable-impedance device. The interrupter would be similar for either concept. Of the two schemes investigated, the liquid metal, variable-impedance device seemed best suited to the application. But to date the use of liquid metal for current limiting has been restricted to low-voltage applications. The development of such a current-limiting element will require a considerable amount of basic research to establish the laws of its behavior well enough to enable the designer to use liquid metal. Clearly, the breaker concept using this technology could be developed to provide reliable and cost-effective breakers for any foreseeable machine sizes. *Program Manager: Narain G. Hingorani*

Removal of PCBs from transformer oils

A year ago, when EPRI's projects dealing with polychlorinated biphenyls (PCBs) were starting, the utility industry was well aware of the need to dispose of or manage PCB contamination in transformer oil. Since then a number of vendors have demonstrated commercial and semicommercial processes for decontamination of oil without sufficient assurance that the processed oil would not be detrimental to insulation life. EPRI's research therefore included confirmation of test methods developed under RP562 and

RP577 that might be used to evaluate treated mineral oils for reusability in transformers. Subsequent to this, the Edison Electric Institute's survey for EPA reported that significantly less contaminated oil was owned by electric utilities than a previous, less exhaustive survey had indicated. This reduced the estimate of replacement oil needed if the treated oil was not considered reusable.

General Electric Co. evaluated four PCB decontamination processes (RP2028-1). Two of these involved separation of PCB from mineral oil by extraction, followed by distillation of the solvent to yield a PCB-rich residue, which left only a small volume of liquid for ultimate disposal. In addition, destruction of PCB contamination by electron beam irradiation and several proposed destruction methods using alkali metals or derivatives were investigated. Of the four, an alkali metal destruction process and liquid extraction appeared most promising. As several alkali metal processes have been demonstrated on a large scale elsewhere, it is now planned to assemble equipment to demonstrate continuous extraction on a pilot scale.

As part of this project the contractor has tested both laboratory-decontaminated oils and several received from utilities that have used one of the commercial demonstration treatments. As of this writing (February 1982), using tests developed in RP562-1, no significant harmful effects have been observed following the above accelerated-life tests of insulation systems in the presence of any decontaminated oils.

Franklin Research Center has developed a double extraction process in the laboratory (RP2028-2). In this process, an efficient, high-boiling solvent, polyethylene glycol (PEG), is used to extract PCB from the mineral oil. However, because the first solvent cannot be removed from the extracted PCB by distillation, other means must be used, such as adsorption on a solid, destruction in the solvent, or a solvent exchange to a second, lower-boiling solvent. All these appear to show promise, and process flow sheets are being developed to optimize one or more of the procedures. Adsorptive removal of PCBs directly from transformer oil is also being investigated with some success.

A separate small study by RTE Corp. bears on the practice of retrofilling PCB transformers or contaminated transformers. It estimates that for a typical 500-kVA transformer containing 500 ppm PCB, about 97.5% of the PCBs are in the oil and 2.5% distributed among the solid components. If, in retrofilling, less than 5% of the original oil is left in the transformer, the concentration of PCB in the new oil would remain below 50 ppm, even if all the PCBs adsorbed by the solid material were desorbed into the new oil. *Project Manager: G. I. Addis*

UNDERGROUND TRANSMISSION

Extruded cable systems

Underground bulk power transmission in the United States is based primarily on paper-insulated, high-pressure, oil-filled (HPOF) cable systems. Over the years, these systems have established an excellent record of reliable operation.

Transmission systems based on cross-linked polyethylene (XLPE) insulated cables, however, offer some potential advantages. Because unlike HPOF cables, XLPE cables do not need to operate in a pressurized-oil ambient, their installation and maintenance are simpler and hence more economical. In addition, at the higher voltage levels dielectric losses represent a significant fraction of total HPOF cable losses (10–25% at 345 kV), whereas dielectric losses are insignificant in XLPE cables.

Unfortunately, experience to date shows that XLPE cables are less reliable than HPOF cables. The major defects affecting XLPE cable reliability are protrusions from the semiconducting shields into the insulation and voids and contaminants in the insulation.

In an effort to overcome these problems and provide advanced XLPE cable systems, a jointly funded project with DOE and General Cable Corp. was instituted (RP7829). The objectives of this project were as follows.

- Develop an insulation processing and cable extrusion system that would minimize cable defects

- Develop XLPE cables rated 138 kV, 230 kV, and 345 kV that have the same physical dimensions as their HPOF cable counterparts

- Develop joints and terminals for the 138-kV cables. (Accessories for the 230-kV and 345-kV cables were to be developed under a second project, once cable development was successfully completed.)

The insulation processing and cable extrusion line was successfully developed, as reported in the final report, EL-428, May 1977.

The 138-kV cable, joints, and terminals have been successfully developed and are currently undergoing extended field tests at EPRI's Waltz Mill Underground Transmission Test Facility. The 230-kV cable has been successfully developed and is awaiting completion of joint and terminal development (RP7858), after which the system will be installed in Waltz Mill.

The 345-kV cable development was not successful. The insulation of these cables was electrically weaker than that of the 138-kV and 230-kV cables. It is believed this was caused by too-rapid cooling of the cable imposed by the shorter-than-normal length of the experimental extrusion line. No problem is foreseen with a full-size manufacturing line.

The experimental manufacturing line developed in this project has been purchased by Pirelli Cable Corp. for production use. *Project Manager: Felipe Garcia*

POWER SYSTEM PLANNING AND OPERATIONS

Generation expansion planning

A two-year project with the Massachusetts Institute of Technology should provide a flexible, modular, user-oriented computer program to develop alternative generation expansion strategies for a utility or pool (RP1529). This program, known as the electric generation expansion analysis system (EGEAS), is a well-documented, production-grade program and was completed in early 1982. EGEAS will be tested and validated on several utility systems in the first half of 1982. Assuming successful validation, the EGEAS program should be available for distribution to interested member utilities in summer 1982.

EGEAS has three features that are significantly different from other generation expansion computer programs. First, the three generation planning functions (generation optimization, production costing, and calculation of reliability indexes) are performed in a single program. Second, a more efficient algorithm (the generalized Bender's technique) is used for the generation optimization calculation. Third, the efficiency of the production cost calculation has been improved tenfold, while including probabilistic effects. This was done by using a more efficient algorithm (method of cumulants) for representing the equivalent load duration curve. In addition, a multiple subyearly period model enables the user to assess the effects of seasonal or time-of-day load variations, system interconnections, storage devices, renewable generation technologies, and maintenance scheduling.

Details of a related project, RP1808, for obtaining the load duration curve are discussed by Jerome Delson in the R&D Status Report of the Energy Analysis and Environment Division in this issue of the *Journal*. *Project Manager: Neal J. Balu*

Effectiveness of dc links in large ac systems

There is a growing interest in dc transmission as a practical adjunct to ac transmission because of environmental and societal constraints on rights-of-way. This trend can be expected to grow in the future.

There is no consistent methodology for evaluating how effective dc links are when integrated with ac systems; this project was initiated to develop such a methodology. The objective of Phase 1 of this project, initiated in March 1981 with Ebasco Services, Inc., was to prepare a reference manual that would guide system planners in evaluating hybrid ac/dc transmission systems (RP1964-1). This reference manual will contain comprehensive methods and procedures for integrating dc links with ac systems and procedures for evaluating their performance and economics; it will also include a discussion of the features and capabilities of available dc controls. The manual should be completed by mid-1982.

The integration of multiterminal (three or more) dc links into an ac network adds a new complication to power system control. Because existing installations are limited to two-terminal dc links, very little information is available on multiterminal dc systems. The objective of Phase 2, initiated in September 1981 with the Institut de Recherche de l'Hydro-Québec, is to focus on the development of advanced concepts and models related to the integration of multiterminal dc links in ac systems (RP1964-2). The scope of Phase 2 includes application of multiterminal dc links; multiterminal dc network analysis; development and validation of models of multiterminal dc controls; and multiterminal dc control strategies. Phase 2 will also incorporate models of multiterminal dc controls in EPRI large-scale load flow and stability programs. *Project Manager: Neal J. Balu*

Transient and midterm stability

Large-scale power system disturbances have become of greater concern to both the industry and the public during the last decade. One approach to minimizing the effects of such disturbances is to analyze their causes. Unfortunately, today's system analysis tools are unable to do this effectively.

The goal of a current five-part research project (RP1208) is to develop new analytic tools to facilitate studies of large-scale disturbances based on a transient/midterm stability computer program developed under RP745. Several new or enhanced features are being implemented in the RP1208 software. Arizona Public Service Co. (APS) is incorporating an improved, two-terminal dc transmission line model, as well as improved machine models and auxiliaries. Arizona State University (ASU) has completed the research involving network reduction and output analysis.

Boeing Computer Services, Inc. (BCS) is providing the numerical integration algorithms and program cleanup. Systems Control, Inc. (SCI), working with Energy Systems Computer Applications, Inc. (ESCA), has developed algorithms for midterm generator aggregations and generator bus reduction. ESCA has added the uniform frequency procedure developed under RP764, *Long-term Power System Dynamics* (EL-367). This option will allow the automatic step-size selection to function better in the midterm simulation region.

The project was started during the first quarter of 1978 and is scheduled to continue through December 1982. With APS's integration and testing complete, BCS is currently working on the final cleanup of the program. Five utilities have tentatively been chosen to use and evaluate the RP1208 code. BCS and ESCA will assist these utilities during the demonstration phase. After necessary modifications, the program will be available for distribution through the Electric Power Software Center. A workshop on models and algorithms for stability calculations was held in August 1981. *Project Manager: John W. Lamont*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

AIR POLLUTION AND MORTALITY IN LONDON

Health effects have been associated with episodes of high air pollution, but there is less certainty about health effects at lower ambient levels of air pollution. Also, information is sparse about the specific air pollutants associated with health impacts. Unfortunately, many of the most severe air pollution episodes have not been monitored, making it impossible to develop quantitative measures of association between air pollution levels and health effects. One exception involves episodes of high air pollution that occurred in London in the late 1950s and early 1960s. During these episodes levels of SO_2 were as great as 10 times the present U.S. primary standard (which is intended to be a level at which human health is not affected). Excess mortality was also evident during the most significant of these episodes. London data from this period have been analyzed to determine the association between air pollution and health. The most recent effort was an extensive EPRI-sponsored study by the Integrated Research Institute, the University of Pittsburgh, and Roth Associates (RP940, RP1642).

The London data will most likely form the epidemiologic cornerstone for the revised SO_2 and particulate primary ambient standards to be set by the U.S. Environmental Protection Agency this year or early next year. Certainly studies of the London data have been cited more than any other epidemiologic studies in the latest EPA criteria document on total suspended particulate matter and SO_2 and in the draft EPA staff standard document for particulate matter.

Earlier studies of the London episodes considered only a limited subset of the available data, generally data from the winter of 1958–1959. These earlier studies also did not attempt to discriminate between SO_2 and particulate matter in analyzing the association between air pollution and human health. The EPRI study was the first to consider the entirety of available London winter data; it also attempted to partition the air pollution–health association between SO_2 and particulate matter.

The EPRI study examined data for 14 London winters beginning in 1958–1959. Winters are defined as the period between November 1 and March 1. Daily air quality data are available from seven London monitoring stations for two pollutants, SO_2 and smoke. The latter provides a measure of particulate levels, although its exact relationship to the U.S. measure, total suspended particulates, is uncertain. Measurements of the pollutants were averaged over the seven stations to provide daily indexes of air pollution exposure. Daily mortality and meteorologic data are available for the entire 14-year period. The mortality data demonstrate significant seasonal trend; that is, the daily mortality levels changed according to a seasonal pattern. Moreover, the pattern varied from year to year. Some seasonal trend can be seen in the air quality data as well. Weather variables were also found to be associated with the mortality and air quality variables, and mortality varied by day of week.

All of these factors, seasonality, weather, and day of the week, were considered in the data analysis. A data set can be analyzed statistically in several ways, and it is not usually possible to specify one analytic approach as being the best. Under such circumstances, alternative approaches that follow good statistical practice should be used to study a data set. The analytic results may converge; but if they do not converge, the results and interpretations are ambiguous.

Analyses were performed that (1) ignored seasonal trend and association with weather and day of the week, (2) adjusted for seasonal trend, day of the week, and weather in the mortality variable, or (3) adjusted for seasonal trend, day of the week, and weather in the mortality and air quality variables. There was some variation in the results of these analyses, but the conclusions did not differ substantively. A statistical argument can be made that the third approach is preferred because it will result in more efficient estimates of the association between mortality and air pollution; that is, statistically significant associations can be detected more easily.

The biggest statistical problem in the London data set is multicollinearity (close association) between the two air quality measures, SO_2 and particulate matter. When the level of one pollutant was high, the level of the other also tended to be high. This makes it difficult to separate any influences of the two pollutants. The EPRI contractors chose to analyze the data set in three ways to contend with this problem.

The first approach involved the development of matrixes based on a two-way stratification of the data. Data from the 14 winters were divided into quartiles according to the value of SO_2, the fourth of the data with the lowest SO_2 values being placed in the first quartile, and so on. Data within each quartile were further divided into quartiles according to the measurements of particulate matter. The result is a nested quartile analysis that allows one to visually examine how mortality changes as particulate levels increase while SO_2 levels are held relatively constant. This procedure was also carried out with the two pollution measures reversed to examine how mortality changes as SO_2 levels increase and particulate matter is held relatively constant. The procedure was carried out both for unadjusted data and for seasonal- and weather-adjusted data. The results suggest a much larger association between smoke and mortality than between SO_2 and mortality; in fact, any SO_2 association appears ambiguous.

The second approach applied a multiple regression model to each of the 14 winters. Results from analyses of data adjusted for both seasonal trend and weather generally demonstrate a positive association between particulate matter and mortality. For 12 of the 14 winters, the association is positive; that is, daily mortality increases with particulate levels. For 3 of the winters, the positive association is statistically significant at the 0.01 level. The SO_2 results are not at all clear-cut. The association between that pollutant and daily mortality is positive for only 9 of the 14 years and negative for the remaining 5 years. Two of the 9 positive associations are statistically significant at the 0.01 level. These are for the winters of 1958–1959 and 1960–1961, both of which had severe air pollution episodes with ambient levels of SO_2 as great as 10 times the present U.S. primary standard. Association between mortality and earlier air pollution values was also examined to determine if there might be a lagged response to air pollution. No evidence for such a response could be found.

If the true association between mortality and a pollutant were zero, we would expect 7 of the 14 years to show a positive association and 7 years to show a negative association. The performance of the SO_2 variable is not significantly different statistically from what one would expect if the true association were zero. The 12 positive coefficients for the particulate variable would occur less than one time in 20, however, if the true association were zero.

The third analysis focused on the subset of days (100) that had the highest 10% of the air pollution measurements. There are two reasons for using this data set. First, it demonstrates a clear association between air pollution and mortality at the high levels of air pollution. Second, the association (correlation) between SO_2 and particulates is substantially lower in this reduced data set (0.53) than in the full data set (0.90). This makes it easier to discriminate between any influences of SO_2 and particulate matter on mortality.

A nonlinear model was applied to this data set. The model included linear and quadratic terms for the two pollutants, as well as a cross-product term. This last term was not found to be significant and was later dropped. The resultant estimated model was used to derive isopleth lines representing equal changes in mortality as a function of changes in SO_2 and particulate levels. The isopleths indicate that if SO_2 is held constant, mortality increases monotonically with smoke over the entire data domain. If smoke is held constant, mortality decreases slightly with any increase in SO_2 up to 0.7 mg/m^3. Then mortality gradually begins to increase with SO_2 levels.

The results of these three analyses of the London mortality data support earlier conclusions that a positive association between air pollution and mortality exists, even after correcting for the confounding influences of annual and seasonal trends and day of the week. The large size of the data base in the EPRI study and the use of three different approaches make it possible to carry the conclusions a step further. It now appears that the association between mortality and air pollution is largely an association between mortality and particulate matter. SO_2 may be associated with mortality, but the evidence suggests that an association most likely occurs at SO_2 levels much higher than the current U.S. primary SO_2 standard. No evidence has been found of any synergistic effect of SO_2 and particulate matter, although more work is needed before this concern is definitively resolved.

There is no straightforward way to translate the particulate measure used in the London study into that defined by U.S. standards. The British measure is based on the opacity of a filter exposed to the ambient air for a certain length of time. The American measure is based on the quantity of particulate matter by weight in a given volume of air. The relationship between the two is not clear. Moreover, the composition of particulate matter in London, especially during the earliest part of the study period, may not be representative of the composition of particulate matter in American cities. For these reasons the study's particulate results must be qualified somewhat in drawing conclusions about the health effects of particulates in the American situation.

The EPRI study is important for two major reasons: It was able to discriminate between SO_2 and particulate matter, which no other analysis of the London mortality data has achieved; it used an extended data base of 14 winters. Earlier analyses of the London data had concentrated on the 1958–1959 winter, during which very high levels of air pollution were experienced. The average daily SO_2 concentration during that winter, for example, was higher than the allowable (primary standard) peak daily level for SO_2 in the United States, which can legally be exceeded only once per year. The results of the EPRI analysis showed that this year was not representative of the years that followed. For this year there was a statistically significant and positive association between SO_2 levels and mortality. The analyses of data from subsequent years do not support this association. The 1958–1959 results may reflect the occurrence of extreme air pollution episodes and/or the occurrence of an influenza epidemic during that winter. More work is needed to determine if a nonlinear dose-response curve could help explain the results of the 1958–1959 data analysis.

With EPRI support a similar analysis was undertaken for 1963–1976 data from New York City (RP940). The results, which have been published in the *Bulletin of the New York Academy of Medicine,* support the results of the London study. Multiple regression analyses of data adjusted for seasonal trend, weather, and day of the week were performed for two seven-year periods (1963–1969 and 1970–1976). Results for both time periods were similar to the London results. There was a positive, albeit small, association between particulate matter and daily mortality. The association between SO_2 and daily mortality was negative, although not statistically significant.

Together the New York and London studies suggest the need for further work to help determine the association between daily mortality and the level of particulate matter. In particular, it would be useful to learn more about the shape of the dose-response curve. To this end, work is being planned to examine London data for the entire year rather than only for the winter. It is hoped that this expanded data base will lead to a better understanding of the association between mortality and particulate matter at lower particulate concentrations. There are also plans to disaggregate the mortality variable in order to focus on deaths from those causes most likely to be associated with air pollution, such as respiratory diseases and cardiovascular diseases. Use of these mortality categories may add sufficient precision to the statistical analysis to clarify the dose-response relationship between particulate matter and mortality, as well as the association between SO_2 and mortality at higher SO_2 levels. *Technical Manager: Ronald E. Wyzga*

GENERATION PLANNING WITH TIME-OF-DAY SENSITIVITY

EPRI's Supply Program is sponsoring a project to help represent more adequately the interaction between load management, storage, and generation planning decisions (RP1808). One goal is to improve the efficiency of production cost calculation and *thereby make it practical to perform calculations necessary to show the effect of changes in hourly load. Another goal is to improve the basic accuracy with which these calculations model the contributions and limitations of storage facilities. The simulation models available to the industry today can only approximately estimate the benefit of storage facilities and hence may misjudge the value of load management.*

Efficient production cost calculation

In generation planning studies, power production costs may have to be calculated many times in order to evaluate each plan. Including the effects of random outages of individual generating units and the effects of daily and seasonal load variation increases the complexity and cost of the calculation. All this is greatly simplified by converting the expected chronological load into a load duration curve. This procedure, which involves arranging hourly loads in descending order of magnitude, has long been standard practice.

A giant stride was made some years ago when the effect of individual generator forced outages was included in the load duration curve to form an equivalent curve of load plus outages. The method proved popular, although it was quite lengthy. More recently, this method has been successfully streamlined. In the newer approach generation outage states, the original load duration curve, and equivalent load duration curves are represented as series of cumulants. (Cumulants are functions commonly used in statistics to describe numerical distributions.) The cumulant method is much faster and can efficiently represent maintenance outages as well as partial and full forced outages.

Much of the basic development work on the cumulant method was conducted at the Tennessee Valley Authority (TVA). Recently, the method was incorporated into EGEAS, a computer program for generation planning under development by EPRI's Electrical Systems Division (RP1529). The work was carried out with the cooperation of TVA, other utilities, the project contractors, and the Energy Analysis and Environment Division. (EGEAS is described by Neal Balu in the R&D Status Report of the Electrical Systems Division in this issue of the *Journal.*)

Ramp-rate and reservoir constraints

Although the efficiency of calculating expected production costs has been greatly improved by the cumulant method, the method—like all other load duration methods—ignores two important constraints and, as a result, may markedly misrepresent the value of a storage facility.

In many systems baseload coal and nuclear units must be controlled so that their outputs are changed only gradually. If the rate-of-change limits (ramp rates) are exceeded, the units will be damaged. Because of this limitation on at least some of the baseload units, changes in overall system load are picked up by other units, and it may take hours before the ramp-rate-limited units are adjusted to their new level of output.

During this long transient, each hour is not treated independently and load cannot be apportioned among generating units solely by the rules of economic dispatch. The sluggishness of ramp-rate-limited units results in the increased use of peaking and storage units. A program that overlooks ramp-rate limits would not simulate this aspect of system behavior and would tend to underestimate the utilization of peaking and storage units.

Another constraint involves energy limits. For example, reservoirs of some pumped-storage plants can support only 6 to 8 hours of full operation. Such plants are probably required to be recharged each night. Other plants, with 20 or more hours of reservoir capacity, are able to operate on a weekly cycle, if desired. A simulation program that does not take into account such reservoir constraints would overestimate the contribution a storage plant could make.

Work is now under way to account for both thermal ramp-rate and energy storage constraints. The first step has been the development of a unique chronological production costing program that explicitly includes these constraints. In comparison with production costing programs that do not include the constraints, this program appears expensive to run. It is not intended, however, to be used frequently. Instead, it is to be used by a planner to make detailed production cost studies for his system. The planner would then use this information for direct manipulation of load duration curves.

The new chronological production program was developed in a joint EPRI–TVA project by researchers at Ohio University and TVA. The project was initiated in 1981, and a prototype version should be available later this year (RP1808). In addition to the application outlined below, the new program may serve as a standard or benchmark for other production costing programs.

Manipulation of load duration curves

Load duration curves are a familiar tool and are particularly useful when production cost-

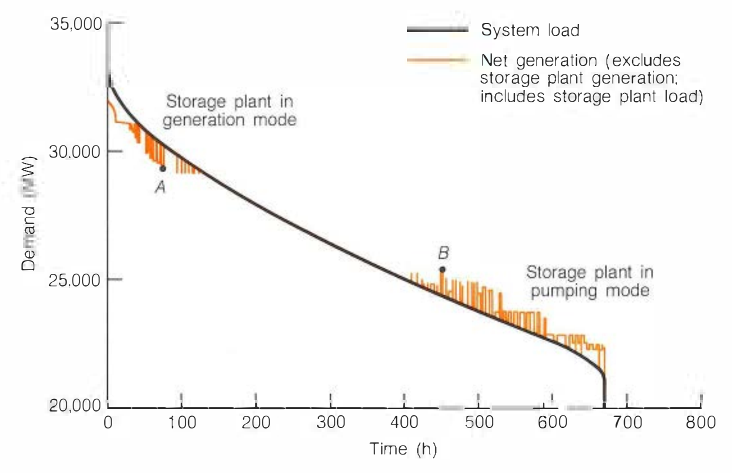


Figure 1 The black curve is a load duration curve representing the system load for a one-month period. The supply system includes a pumped-storage plant that serves part of the load when it generates and adds to the system load when it pumps. The colored curve shows the load on the other units as modified by the pumped-storage plant. Point *A*, for example, represents the load on these units for an hour when the storage plant is generating at full output, and point *B* shows an hour when the storage plant is being recharged. The colored curve uses the same chronology as the original curve and reflects the limits and economic decision rules that guide storage plant operation.

ing is a frequently used subroutine in a planning model. As noted earlier, to form a load duration curve, hourly loads are arranged in descending order of magnitude. An example is the black curve in Figure 1, which represents a system load for a one-month period.

If a pumped-storage unit is included in the capacity mix, the load on the other generating units is reduced whenever the storage plant is producing power. This generally occurs during peak hours. Conversely, the load on the other units is increased during those off-peak hours when the storage plant is being recharged. The development of the load duration curve for the other units is shown graphically in two steps in Figures 1 and 2.

The colored curve in Figure 1 shows what happens to the load on the other generating units for each individual hour. These loads have not been re-sorted into descending order but rather are shown in the same order as the corresponding loads in the black curve. The result is a jagged curve that reflects operator decisions based not only on economic considerations but also on a recognition of the limitations imposed by reservoir size and the need to allow for uncertain future conditions.

In Figure 2 the colored curve has been redrawn with the data points arranged in the usual descending order. Power system planners would like to be able to obtain such results without having to perform the hour-by-hour analysis and detailed calculations used here.

Work on the direct manipulation of load duration curves is a separate part of the investigation under RP1808 and is being conducted at TVA, Ohio University, and Cornell University. The researchers hope to derive a new cumulant function that would include thermal ramp-rate and energy storage constraints and would be based on a few select, detailed production cost studies. This technique would be applied initially to pumped-storage plants. If successful, it may also prove useful for the analysis of other time-dependent operations. *Project Manager: Jerome Delson*

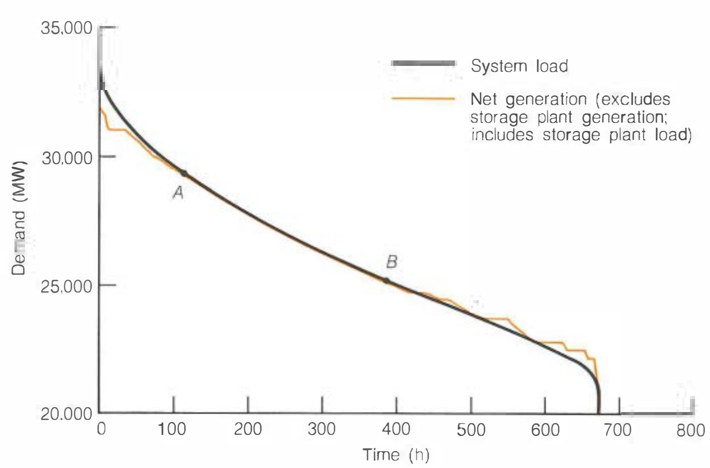


Figure 2 Here the loads in the colored curve have been sorted into descending order, as required for system planning models. Points *A* and *B* have now shifted position.

LOAD MANAGEMENT STRATEGY TESTING MODEL

Load management and conservation planning is a challenging problem for utility managers. EPRI has sponsored the development of a tool to help meet this challenge, the Load Management Strategy Testing Model (LMSTM), which is scheduled to be available in mid-1982 (RP1485). Designed for use by utilities in evaluating load management and conservation alternatives, the model combines detailed information about a utility's loads, production system, rates, and finance into one easy-to-use package. It provides a detailed technical assessment of planning alternatives and a framework for communication among diverse groups both within and outside the utility. The resultant analyses address load management and conservation planning in a way that enables its complexities to be articulated and explained.

Demand-side planning

Consideration of demand-side options, such as direct load control of customer appliances, time-of-use pricing, and conservation programs, greatly complicates traditional utility planning for capacity expansion.

▫ There are many potential demand-side options to evaluate, and their costs and benefits interact. For example, a single communication system can control more than one load management device, thus lowering the cost of controlling additional customer appliances; the benefits of load reductions made during a morning peak with one device can be sensitive to the control strategy selected for another device during an afternoon peak. Such interactions require a planner to exercise considerable judgment and intuition in identifying particularly cost-effective combinations of demand-side options.

▫ There are many different criteria for evaluating demand-side alternatives. For example, one load management option may reduce revenue requirements but impose indirect costs on customers through reduced reliability.

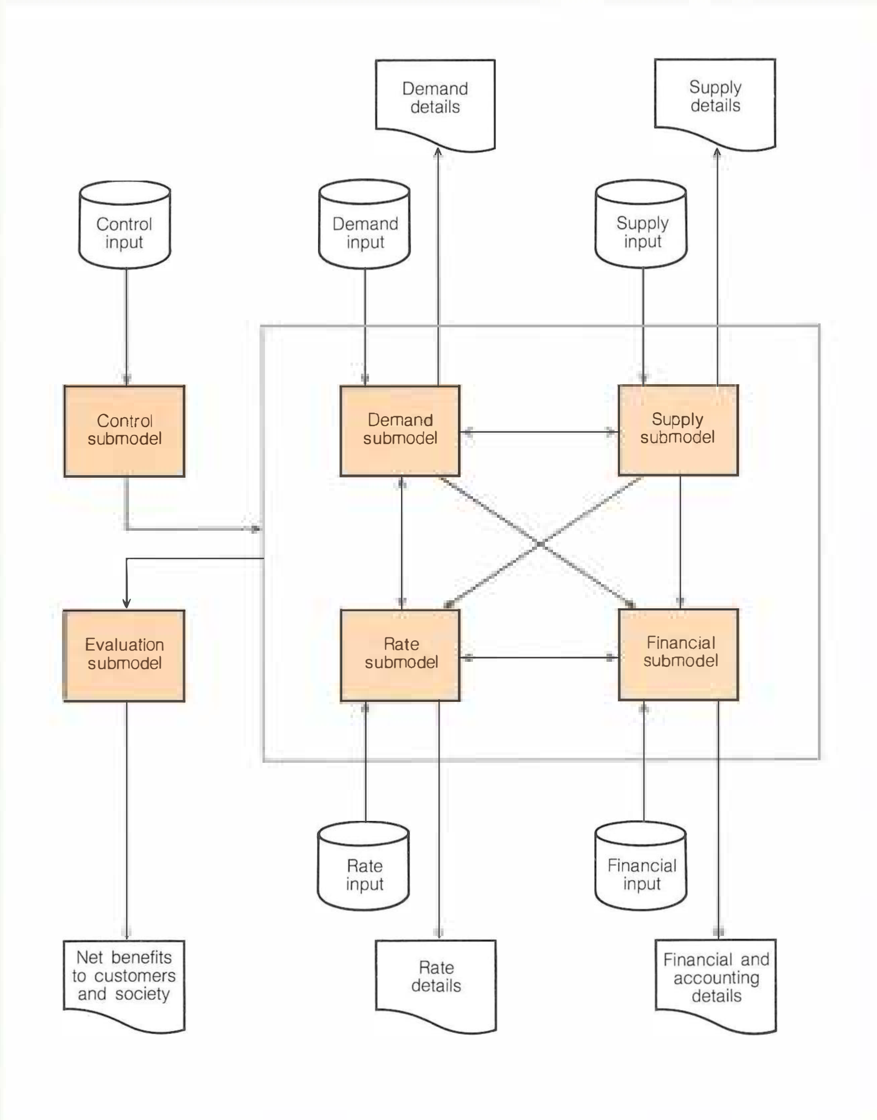
▫ The analysis of demand-side options can require technical detail not usually necessary for traditional supply-side planning. Two examples of such detail are end-use specificity in load forecasts and the hourly joint dispatch of storage units, direct load control devices, and thermal capacity.

▫ As on the supply side, planning demand-side options is fraught with uncertainty. The success of demand-side options is believed to be particularly sensitive to load growth, changes in fuel prices, and customer response to load management—all of which are uncertain variables.

Model features

To help utility planners cope with these difficulties, EPRI's Systems Program initiated a project with Decision Focus, Inc., to develop a load management planning model (RP1485). The product of this effort, LMSTM, is composed of four submodels that represent the utility system, plus a control submodel and an evaluation submodel (Figure 3). Because it was built from the ground up to examine demand-side planning options,

Figure 3 The Load Management Strategy Testing Model. The submodels shown in the gray box represent a utility system and can produce detailed system simulations. By comparing simulations that include load management options with those that do not, utility planners can determine the impact of load management on the utility and its customers.



LMSTM has a number of attributes not commonly found in traditional planning models.

The model's integrated structure combines supply, demand, rate, and financial simulation capabilities in a single package. This facilitates model use, helps ensure consistency of assumptions, makes it easier to do a complete analysis, and reduces model solution time. Thus the user can quickly obtain a comprehensive view of the implications of a large number of demand-side options.

LMSTM's components have the technical detail required for analyzing demand-side planning options. The demand submodel projects system loads by customer class, end use (e.g., space heating, air conditioning), and technology within end-use categories (e.g., heat pumps, resistance heat). This detail is necessary because controlling specific end-use loads and technologies is often the objective of a load management plan.

The supply submodel projects power plant operating costs, giving explicit consideration to the probabilistic nature of plant availability. On an hour-by-hour basis, the submodel simultaneously dispatches thermal power plants, energy-limited hydro plants, pumped-storage units, and direct load control devices. Thus the interactions between load management options, thermal-unit availability, and the operating parameters of central station storage are simulated. This detail is necessary to estimate the impact of load management on production costs and reliability in an operating environment.

The rate submodel can simulate a variety of options by customer class, including time-of-use rate options. It enables the analyst to examine different ratemaking approaches in these areas: allocation of costs to time periods, marginal-cost versus accounting-cost rate definition, treatment of revenue reconciliation, and treatment of credits and rebates for participation in load management programs.

The financial submodel tracks the multiple effects of load management on revenues, investment, and depreciation. This detail is necessary because demand-side options can involve different patterns of investment, depreciation, and financing than supply-side options.

Through the control submodel the user specifies global parameters, such as the base year, the simulation horizon, assumptions about inflation and the real escalation of costs, and the discount rates to be used in calculating the present value of costs and benefits. In this submodel the user also sets the amount of detail desired in the printed results.

The evaluation submodel estimates the total benefits of providing electric power service minus the total costs. These estimates are calculated for each year, and the present value of net benefits is calculated for the entire simulation period. A comparison of these results for two simulations, one with a load management option and one without, provides a bottom-line evaluation of the load management option from the customer's perspective. This submodel also computes the capital budgeting implications of load management options.

Table 1 lists the major inputs, outputs, and data flows for LMSTM's utility system representation submodels. Flows from the input files take place at the beginning of model runs. The other flows take place for each year of the simulation period (typically 5–15 years).

Another important feature of LMSTM is that it comprehensively treats the effects of demand-side planning options. The financial submodel produces such statements as balance sheets, flow-of-funds statements, and income statements. The evaluation sub-

Table 1
INFORMATION FLOWS IN LMSTM'S UTILITY SYSTEM SUBMODELS

Information Source	To Demand Submodel	To Supply Submodel	To Rate Submodel	To Financial Submodel	To Output Files
Input files	Number of customers Appliance mix Weather sensitivity Price responsiveness Load management device parameters	Current capacity Planned capacity Plant characteristics Fuel prices	Customer class and rate period definitions Rate structure, revenue reconciliation, and cost allocation options	Base-year financial statements Term structure of debt and rate base accounting options	Echo of input data
Demand submodel		Loads by hour Direct load control potential	Sales by class Customers by class	Distribution and meter investment Direct load control investment	Hourly loads by customer class, end use, and end-use technology Annual energy use
Supply submodel	Use of direct load controls		Hourly production costs (average and marginal) Use of direct load controls	Plant construction expenditures	Production costs Plant utilization Detailed plant dispatch Direct load control and storage dispatch Unserved energy Indirect costs (environmental)
Rate submodel	Rates by hour and season for each class			Total revenues	Simulated rates by hour, class, and component
Financial submodel			Fixed costs to be recovered		Financial statements Rate relief needed Investment and financing

model estimates changes in consumer surplus, a measure of customer well-being that is appropriate when both rates and usage change. The model also tracks customer investment in response to load management (e.g., the purchase of more efficient appliances or thermal storage systems), as well as reliability changes due to load management. Miscellaneous social impacts—for example, oil use (national security) and environmental emissions—can also be considered at the user's discretion.

The model is flexible, permitting users to explore the implications of uncertain variables in either a single sensitivity analysis or a more complex decision tree structure. Because the inputs are easy to change and the model can be run quickly, the user can estimate the implications of many uncertainties and thus identify the demand-side planning strategies that are most robust over a wide range of possible futures.

Development and transfer activities

LMSTM was developed in close cooperation with the utility industry over a 22-month period. The project consisted of two phases: a development phase, in which the general structure was designed and the model tested in prototype form; and a transfer phase, in which the model was refined and documented for transfer to utilities.

At the start of the development effort, a workshop was held to obtain industry input on the initial design of the model. Following this workshop, three test utilities were selected to work with the contractor as the design was implemented. These utilities—Carolina Power & Light Co., Northern States Power Co., and Public Service Co. of New Mexico—applied the prototype model with their own data. Their feedback was valuable in ensuring a planning tool that would be usable by utilities. The development phase concluded with two workshops to discuss the prototype model and the test utility experiences. Many suggestions for improvements were made at the workshops and have since been included in the model.

In the transfer phase of the project, the contractor developed a final production version of the model. This version and a user's guide are currently being tested in a case study application at another utility. They will be available through the Electric Power Software Center once this field testing is completed (mid-1982). An EPRI report describing the model's overall design and major components will also be issued at that time. *Project Manager: Victor Niemeyer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Director

CHEMICAL ENERGY CONVERSION

*The primary objective of this subprogram is to explore chemical energy conversion (CEC) systems and processes that may have potential for linking energy sources (especially electric energy) more efficiently and productively with specific energy uses. Currently, subprogram activities focus on CEC processes in two technical areas: on hydrogen produced from electricity and water by electrolysis (the hydrogen can be used as a fuel, a chemical, or an energy carrier by utilities or their customers) and on electrosynthesis of industrial chemicals. Earlier technoeconomic assessments of (1) hydrogen production by water electrolysis and by thermochemical processes and (2) comparative evaluations of reversible chemical processes to store and/or transport thermal energy have resulted in the current narrower scope of subprogram activities. These assessments were discussed in previous R&D status reports (*EPRI Journal*, December 1979, p. 39, and March 1981, p. 55).*

Electrolytic hydrogen for generator cooling

Several feasibility analyses, utility surveys, and market evaluations conducted during 1975–1981 are the basis for the following conclusions.

▫ Practical integration of hydrogen as an energy carrier with utility system operations will require lower-cost methods of hydrogen production than are currently projected for either electrolytic or thermochemical processes.

▫ Hydrogen produced by water electrolysis could represent a considerable cost savings to utilities over the commercial (merchant) hydrogen now used for generator cooling.

▫ Demonstration of reliable, cost-effective, and efficient water electrolyzers for generic utility applications, such as generator cooling, would establish hands-on utility experience with electrolytic hydrogen production technology and provide the industry with an entry for other hydrogen applications that are likely to be developed in the future.

Hydrogen has a lower density and better cooling properties than air. Thus for many years turbine generators have been designed to operate in a hydrogen atmosphere in order to reduce windage losses. To maintain adequate hydrogen pressure and purity within the generator casing, pure hydrogen must be supplied to make up for leakage primarily through shaft seals. Depending on the age and condition of the unit, hydrogen losses can range from 1–2 ft^3/d (0.028–0.056 m^3/d) for each MW of capacity in new units up to several times this amount in older machines. Hydrogen for generator cooling is normally supplied in pressurized cylinders and tube trailers by merchant gas distributors. Technoeconomic analysis shows that at annual hydrogen consumption rates of less than 100×10^6 ft^3 (2.8×10^6 m^3), on-site electrolytic hydrogen could be cost-competitive with average merchant hydrogen prices (RP1086-4). This includes almost all generator-cooling applications.

Electrolyzer development and demonstration

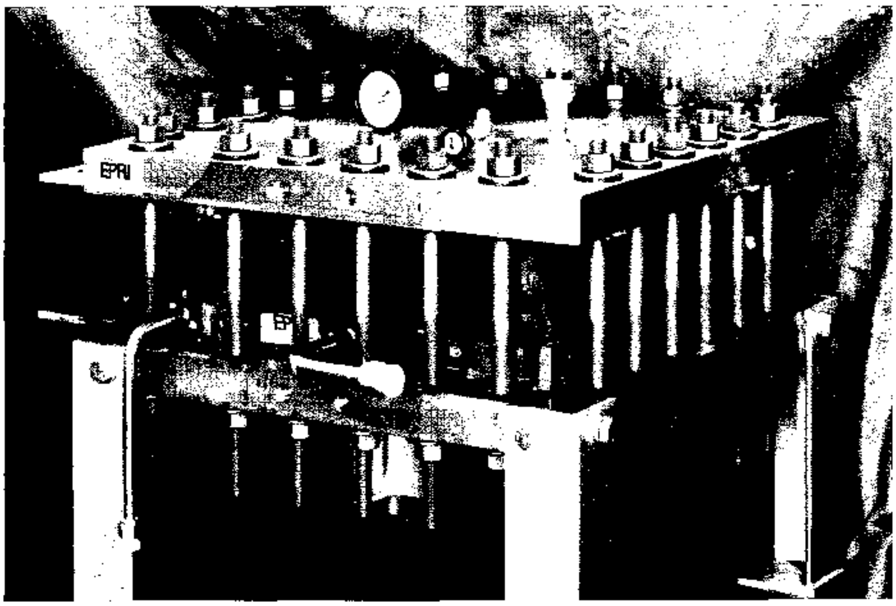
Utility specifications for generator coolant (hydrogen) requirements were developed by a utility advisory group and used as the basis for the design and development of two advanced water electrolyzers. General Electric Co. developed a solid-polymer electrolyte-based electrolyzer (RP1086-5) and Teledyne Isotope, Inc., developed an alkaline electrolyte water electrolyzer (RP1086-06). As a participant in a coordinated program involving utilities, potential vendors, and DOE, EPRI sponsored the development of reliable and efficient electrolysis modules consisting of a number of individual cells in a filter-press-type bipolar stack. These electrolysis modules are installed in systems designed by the manufacturers for controlled production of hydrogen. Final designs of utility hydrogen-generating systems are not complete, and both manufacturers have prototype units on test (Figures 1 and 2).

To demonstrate the reliability and economic viability of this application, two host utilities will install, operate, and evaluate the prototype units. Public Service Electric and Gas Co. (PSE&G) of New Jersey has procured the prototype system from General Electric, and EPRI is providing the 20-kW (~200-ft^3/h [5.7-m^3/h] hydrogen) electrolysis module mounted in the system (RP1086-07). PSE&G will also install a compressor at its 790-MW Sewaren, New Jersey, station to raise electrolytic hydrogen pressure from 100 to 1250 psig (from 689 kPa to 8.6 MPa) for on-site storage. The prototype unit will be evaluated for two years, starting June 1982.

The General Electric prototype unit was factory-tested for five months to qualify it for unattended, safe operation. These tests included simulation of many of the expected operating conditions and prototype response to cycling hydrogen demand. After initial checkout and operational tests, the unit completed the acceptance test in December 1981, meeting the criteria for a hydrogen production rate of 180 ft^3/h (5 m^3/h), minimum, of 99.95 vol%, minimum, pure hydrogen at 100 psig (689 kPa) delivery pressure and −40°F (−40°C) dew point. The acceptance tests were witnessed by PSE&G and EPRI staff and the unit was operated by Sewaren station personnel during acceptance tests. Currently the unit is waiting to be shipped to Sewaren in June 1982, when the facilities will be ready for installation of the electrolyzer.

The Teledyne unit will be evaluated for two years by Allegheny Power System, Inc., at its Pleasants, Pennsylvania, station. APS will procure the 50-kW prototype system and power supply from Teledyne and EPRI will supply the 50-kW electrolysis module. Factory testing of this unit has identified a few technical difficulties that have delayed ac-

Figure 1 Prototype electrolysis module developed by General Electric Co. This solid-polymer electrolyte-based electrolyzer will be tested and evaluated on the system of Public Service Electric and Gas Co. of New Jersey.



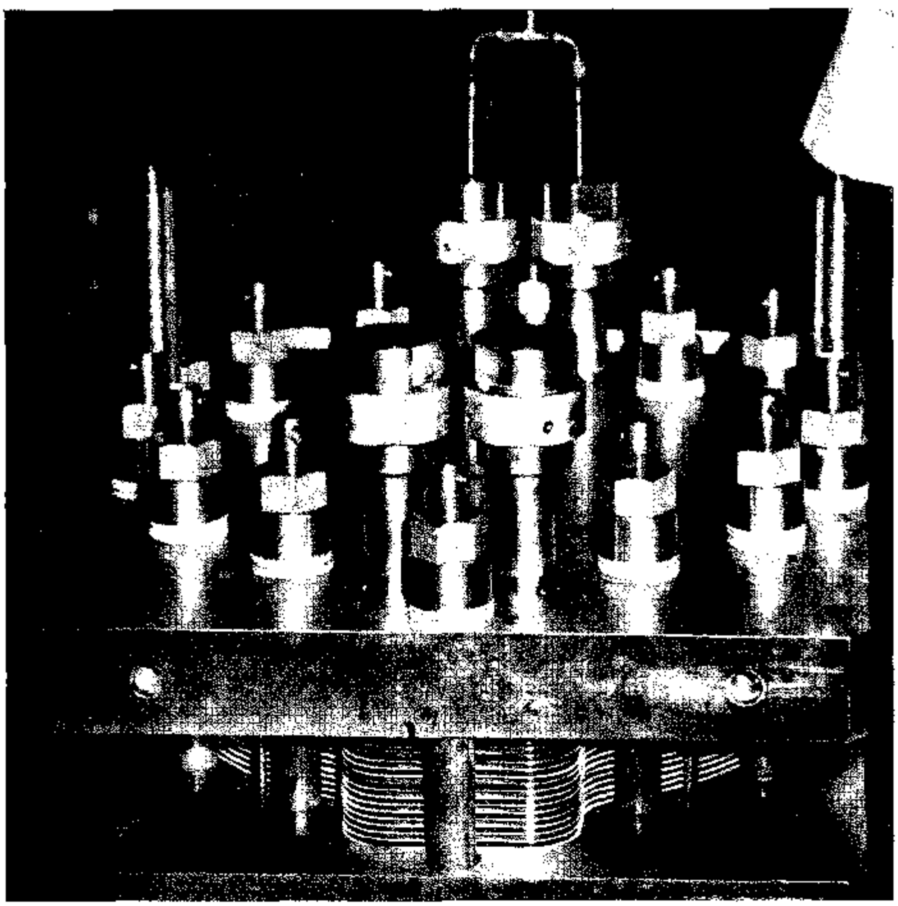


Figure 2 Prototype electrolysis module developed by Teledyne Isotope, Inc. This alkaline electrolyte water electrolyzer will be evaluated by Allegheny Power System, Inc., at its Pleasants, Pennsylvania, station.

ceptance testing. When the unit has been accepted by EPRI and APS, it will be installed in Pleasants.

For the next two years, hands-on operation and maintenance data by both host utilities will validate the on-site electrolytic hydrogen supply concept and its reliability and cost-effectiveness. If the industry experience with electrolysis equipment is satisfactory, expanded applications and equipment improvements will be explored by EPRI.

Electrosynthesis of chemicals

There is a growing perception that emerging electrotechnologies, such as electroorganic synthesis, have potential for development into more productive and economic ways of making metals, chemicals, and other products. In April 1981 a workshop was organized by SRI International to discuss the industrial prospects and R&D progress related to the electrochemical synthesis of organic compounds (RP1086-09). About 30 participants, representing a balance of industrial, academic, and institutional expertise, discussed electrosynthesis processes and potential impacts on utilities (EM-2173). The first and (to date) only large-volume electroorganic process, the synthesis of adiponitrile, was brought on-stream by Monsanto Co. in 1965. Participants from Monsanto revealed that the cost of electricity consumed and the capital required for electrochemical plant equipment represent only 10–15% of product cost, and thus do not significantly affect the plant or production costs. This tends to contradict the general notion that electrochemical processes are handicapped by being exceptionally capital-intensive. However, at present there is no clear indication that a large electroorganic industry will develop in the United States in the nearer term. To improve our understanding, SRI International is currently determining the industrial potential for cost-competitive manufacture of large-volume organic chemicals through innovative electrochemical processes (RP1086-11). Other opportunities of industrial electroprocesses, such as on-site chlorine or ozone generation for utility applications and a coal-arc process for making acetylene, will be evaluated this year. *Project Manager: B. R. Mehta*

1980 SURVEY: UTILITY CONSERVATION, SOLAR END USE, AND LOAD MANAGEMENT

For the past several years, EPRI and DOE (Oak Ridge National Laboratory) have jointly sponsored surveys of conservation and load *management projects within the electric utility industry. In 1980 the survey was updated and expanded to include solar end-use activities (EM-2193). The survey reflects increased utility activity and contains more detailed project information than in previous years because more data have become available for projects nearing or reaching completion.*

The overall objective of the survey was to consolidate technical information emerging from widely dispersed utility-sponsored programs and to present this in a format useful to the utility industry and for the planning of end-use R&D at EPRI. Although a large number of currently active or recently completed projects were identified and surveyed, the study did not attempt to report all utility activity.

Information used in the report was compiled from responses to a mail survey of investor-owned, large municipal, and rural electric utilities; from queries to state associations; and from a review of trade journals and newspapers. These efforts were supplemented by several hundred telephone interviews and a number of personal visits.

Results of the survey showed that utility involvement in customer-side load management, energy conservation, and solar projects has increased steadily and significantly over the past several years. In some cases, regulatory commission and government mandates account for this increase. But the primary motivating factor for utilities is the potential for decreasing the cost of supplying electricity. Energy conservation, solar, and load management projects can result in the deferral or downsizing of planned programs to construct new generation and transmission facilities, in the reduced use of expensive peaking fuels, and in lower purchased-power costs. As a consequence, utilities are able to meet demand more efficiently and at lower cost.

The report is issued in three volumes on conservation, solar end use, and load management. It includes the type and extent of activities being conducted by individual utilities; describes the various systems and devices being tested; lists specific utility contacts for obtaining more detailed information; gives key results and conclusions of individual projects, including utility impacts and feedback; and contains listings of equipment manufacturers. To the extent that information was available, the report also details current cost data on equipment being used and evaluates the relative economics of the various systems to indicate their potential attractiveness to utility cus-

Table 1
1980 SURVEY

Activity	No. of Projects	Comments
Conservation		
Energy-conserving devices, systems, and programs	59	Energy audit; weatherization and insulation; heat pumps
Heat recovery devices, systems, and programs	14	Refrigeration heat recovery; heat pump water heating; power plant discharge heat recovery
Award and incentive programs	20	Presentation of awards to customers meeting certain standards; low-interest loans; high-efficiency-appliance rebates; National Energy Watch
Information, education, and display programs	27	Information centers, displays and demonstrations; advertising and public relations; workshops and training programs; promotion of energy-efficient appliances and conservation products; energy-efficient demonstration homes
Energy-conserving rates, rules, and standards	10	Minimum insulation standards for new service; special rates for customers who use certain types of equipment, cogeneration, or on-site generation powered by wind, sun, biomass, refuse, or water
Solar		
Water heating	97	Projects ranging from 1 to 10,000 installations
Space and water heating	56	Projects ranging up to 40 installations
Space heating and cooling	49	Active solar, 26; passive solar, 23
Process heat, agriculture, biomass, and photovoltaics	28	Process heat, agriculture, biomass, 14; photovoltaics, 14 (including 5 projects larger than 50 kW)
Wind energy conversion	31	Horizontal axis, 28; vertical axis, 6; some projects on both designs
Weather data collection	15	Wind and insolation
Component evaluation	7	Vacuum tube collectors, pool cover, solar shade screen, among others
Load Management		
Thermal energy storage	86	Central ceramic heat, 23; room ceramic heat, 8; pressurized water, 9; in-ground, 3; ice, 23; combination heat and cool, 11; miscellaneous, 9
Communications and load control	158	Radio control, 68; ripple control, 22; power line carrier, 22; combination radio and power line carrier, 18; telephone control, 5; local control, 15; miscellaneous, 8

tomers and, thereby, their potential for affecting utility load patterns. The number and types of projects discussed in the report are given in Table 1.

Conservation activity

A total of 130 end-use conservation projects undertaken by 66 individual electric utilities are described in the report.

The survey makes clear that adoption and implementation of energy conservation programs is now practically universal within the industry. In a few cases, individual utilities are conducting as many as 20–30 separate programs, with budgets in the millions of dollars. Most large- and medium-size utilities have established energy conservation departments or divisions, while smaller ones have at least one staff member designated to act as the energy conservation coordinator or specialist.

Solar activity

A total of 283 end-use solar projects involving 119 utilities are described. The projects cover virtually every known customer-side solar technology application. Monitoring customer installations, supporting university research, conducting in-house RD&D, and promoting solar energy use through interest-free financing and technical advice are some of the types of activities being conducted.

Solar water heating appears to be of greatest interest to utilities and is potentially the most cost-effective of solar end-use technologies. When properly sized, active space-heating systems can offer small benefits to some winter-peaking utilities but are economically less attractive to customers than water heating. Generally, active space- and water-heating systems are best suited for utilities with a high cost of supply and little or no cost variations with time of day.

Utility involvement in passive test programs is continuing to increase. Well-designed passive solar homes can reduce energy use to less than a half of its current value for conventional homes. Preliminary data indicate that this technology could be beneficial to the load composition and profile of the utility involved.

Small wind energy conversion systems are becoming more popular with utility customers. But because of their high cost, they can be economically attractive only to customers experiencing very high electric rates and high, sustained winds (i.e., annual average wind speeds in excess of 12 mph).

Photovoltaic systems for customer-side applications remain prohibitively expensive, and are not expected to have any near-term impact on utilities. Biomass, agricultural, and solar industrial process heat systems tend to be attractive to utilities whose customer base is largely agricultural or whose industrial customers are willing to experiment with novel systems.

Load management

A total of 244 load management projects involving 186 utilities are discussed in the report. Of these, 86 projects (59 utilities) involve thermal energy storage, and 158 projects (127 utilities) involve communications and load control. The obvious appeal of both of these technologies is their potential for reducing peak loads and improving overall load factors.

Thermal energy storage is used to level or shift completely off-peak space-conditioning and electric water-heating demands. The load management potential of this technology is significant: more than 60% of the energy consumed by the residential sector is for space heating and cooling, with electricity powering essentially all cooling devices and an increasing percentage of heating equipment. Cooling demand, and in many cases heating demand as well, coincides with utility peak loads.

However, thermal energy storage systems are also considerably more expensive than the conventional heating or cooling systems they would replace. Nevertheless, with demand and time-of-day rates, cool storage for commercial buildings and residential heat storage systems are already economically attractive in some utility service areas. Residential cool storage technology has to be substantially improved before it can be commercialized.

Factors utilities must weigh in evaluating the economics of promoting thermal energy storage include the potential size of the peak demand reduction, the value of the reduction (which is dependent on various factors, including wholesale power costs and costs of new generation and distribution equipment), and the potential trade-off between the rate differential the utility feels it can afford and that required to make the system economically attractive to consumers.

Communications and load control strategies are designed to control customer demand. The most commonly controlled loads are water heating and air conditioning. In addition, communications and load control systems are used with electric space heating, irrigation pumps, and other loads.

The basic devices for point-of-use load control are mechanical switches, such as those used in time switches and thermostats. Several devices have been developed that add local, on-site logic to the simple switching function. Some of these devices interface with a remote communication system; others are designed to operate entirely autonomously.

The 158 projects reported in the survey are categorized by the activation technology employed: radio, telephone, power line carrier, ripple, and local autonomous systems. The projects range from tests of local, time-controlled switches to centrally controlled systems, and while most of the projects are demonstrations, 66 are systemwide or near systemwide in scope. *Project Manager: Veronika A. Rabl*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Director

HYDROGEN COMBUSTION AND CONTROL

EPRI has initiated a program to study hydrogen combustion behavior in the LWR containment building environments that could follow severe postulated nuclear accidents. Flammability limits, deflagrations, burn control methods, equipment survivability, and hydrogen mixing and distribution in hydrogen, air, steam, and water spray environments are being investigated in several projects. Analytic models and computer codes are also being developed and evaluated for combustion behavior and for hydrogen mixing and distribution processes.

The possible consequences of hydrogen generation during a nuclear core uncovery have received increased attention in the aftermath of the Three Mile Island accident. Substantial quantities of hydrogen can be produced by the reaction between steam and the zirconium-alloy cladding of the nuclear fuel at the high temperatures that may occur during a prolonged core uncovery. This hydrogen produces no threat in the high-pressure coolant system because of the lack of gaseous oxygen. However, when mixed with air in the large reactor containment building, hydrogen could pose a potential threat to safety-related equipment and ultimately to the containment structure itself.

The combustion problem is complicated by the presence of steam, water fog, water spray, large volumes, and complex geometries. Various initial conditions can also be involved, depending on the mixing behavior of the hydrogen-steam source and the mixing effectiveness of natural and forced convection processes.

One of the suggested methods for controlling and mitigating the severity of possible hydrogen combustion is the use of a deliberate ignition system by which hydrogen would be burned before accumulating locally to dangerous levels. The maintenance of water fogs, the use of flame suppressants, pre- or postaccident inerting, and other methods have also been suggested.

Current EPRI research focuses on hydrogen combustion behavior with studies of the deliberate ignition, water fog, and water spray approaches to hydrogen control. Concerns related to nuclear plant licensing have accelerated the EPRI schedule to obtain data in realistic environments and geometries, and the primary near-term objective is to determine and demonstrate methods of effective hydrogen control.

Five experimental and two analytic projects were initiated during 1980–1981 and are providing the primary information to satisfy the research objectives. American Electric Power Service Corp.; Atomic Energy of Canada, Ltd.; Duke Power Co.; Ontario Hydro; and Tennessee Valley Authority have participated in the funding for the early work. The experimental research is being accomplished in test volumes ranging in size from 0.017 to 2100 m^3. The projects are related and consist of the following.

- Hydrogen combustion studies at the Whiteshell Nuclear Research Laboratory, Atomic Energy of Canada, Ltd., in Manitoba (combustion behavior and igniter effectiveness in steam environments, using 0.017-m^3 and 6-m^3 vessels)

- Hydrogen control studies by Acurex Corp. at a test site near Livermore, California (simulated accident conditions and deliberate ignition with dynamic hydrogen injection, water spray, water fog, and equipment survivability in 18-m^3 vessel)

- Hydrogen mixing and distribution studies at the Hanford Engineering Development Laboratory (HEDL) in Richland, Washington (hydrogen-steam injection into a compartmented 850-m^3 vessel; study of mixing behavior)

- Large-scale demonstration at DOE's Nevada Test Site (simulation of accident environments in 2100-m^3 vessel; study of hydrogen control systems and equipment survivability)

- Effects of water fog on lower flammability limits at Factory Mutual Research Corp. in Norwood, Massachusetts (bench-scale study of fog effects on flammability limits)

- Modeling of hydrogen combustion at Factory Mutual

- Calculation of hydrogen distributions at Battelle, Pacific Northwest Laboratory in Richland, Washington

Thermal igniters proposed by some utilities for use in deliberate ignition hydrogen control systems are under study in the 0.017-m^3 vessel at Whiteshell. The glow plug igniter, which was installed in TVA's Sequoyah plant and in other plants, was used in a series of experiments, and flammability limits are being mapped as a function of steam concentration. The igniter is a General Motors AC-7G diesel engine glow plug, requiring a transformer and 12 or 14 V for use in a distributed ignition system. EPRI has acquired two other igniter designs for direct operation on 110–120 V, and one will be used in a second series of bench-scale tests at Whiteshell. Glow plug surface temperatures at ignition are also measured in these tests and are generally found to increase with increasing steam concentration. Nevertheless, all flammable mixtures ignite at temperatures significantly below the proposed NRC requirement for glow plug operation.

Basic hydrogen combustion studies are also being performed in a 2.3-m-diam, 6-m^3 sphere at Whiteshell. Hydrogen, air, and (in most cases) steam are premixed in the sphere at a temperature of 100°C. The combustion of lean mixtures and laminar and turbulent deflagrations are under study. A 0.3-m-diam, 6-m-long pipe is being connected to the sphere in some experiments in order to study combustion from one compartment to another and to investigate the important questions of flame acceleration and the potential for transition to detonation. Figure 1 shows the effect of steam on a mixture with 8% hydrogen by volume. At

Figure 1 Effect of steam on hydrogen combustion in a 2.3-m-diam sphere (8% hydrogen, bottom ignition, without fan turbulence, 100°C). This is one of the combustion studies performed by Atomic Energy of Canada, Ltd., at its Whiteshell Nuclear Research Laboratory.

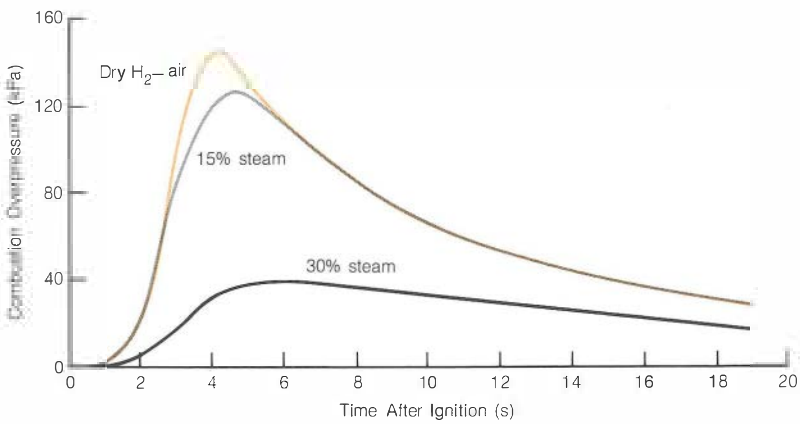
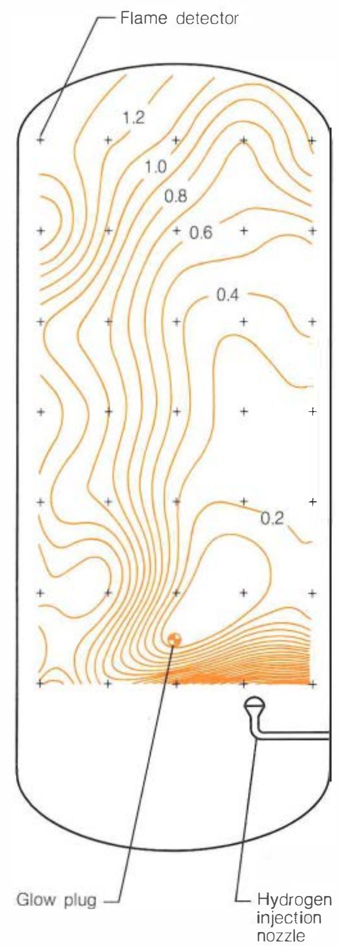


Figure 2 Flame contours for approximately 1 s after ignition by a thermal glow plug and about 2 min after start of hydrogen injection into an 18-m³ cylinder.



least 4% hydrogen by volume in dry air is required for minimal combustion, and combustion with 8% hydrogen is significantly affected by the presence of 30% steam. Approximately 55% steam is found to inert all hydrogen mixtures. Even with a dry stoichiometric mixture of 30% hydrogen at 100°C, the highest pressures observed have been less than 483 kPa (70 psi), far lower than those associated with detonations. There is no indication that a detonation could occur with glow plug or spark ignition sources, according to the Whiteshell facilities.

Factory Mutual has examined the effects of water fog on lower flammability limits in a bench-scale apparatus. It has found that even a dense fog of small droplets has little effect on hydrogen flammability. In nuclear plants, fogs may occur from steam condensation or may be produced deliberately as a control measure.

Hydrogen control by deliberate ignition is being studied in degraded core accident simulations by Acurex. Most of the experiments feature continuous injection of a hydrogen-steam source into an 18-m³ cylinder containing a preenergized glow plug. The vessel was fitted with the standard containment spray nozzle used in many LWRs, as well as with several microfog nozzles, three standard glow plug igniters, a nozzle for premixed hydrogen-steam injection, and a series of 35 flame front detectors.

The dynamic injection tests were intended to simulate the amount of hydrogen released to containment following a small-break degraded core accident. Figure 2 is a burn contour map of dry hydrogen injected at a high rate into the vessel. The bottom axisymmetric igniter location is indicated by a partially shaded circle. Ignition took place about 2 min after the beginning of injection and resulted in some upward flame speeds of about 3 m/s and horizontal speeds of 1–2 m/s.

Several parameters have been varied in the Acurex tests, including the amount of hydrogen and steam flow; the ignition location; presence of water spray, water fog, and fans; and microfog drop size. The pressure rise for the combustion in Figure 2 was about 159 kPa (23 psi). Pressures are generally lower when steam is injected with the hydrogen and are much lower when water sprays are activated prior to the hydrogen injection. Quiescent tests with premixed atmospheres of hydrogen and steam have also been performed, and a series of experiments on equipment survivability has been completed. All items of equipment—which included a solenoid valve, pressure transmitter, valve operator, limit switch, resistance temperature device, thermocouple, and electrical cable—operated successfully both during and after exposure to the hydrogen burn.

Hydrogen mixing and distribution is being studied at HEDL. A 20-m-high, 7.6-m-diam vessel has been fitted with a deck, with provision for some convective flow from the lower to the upper compartment and for forced flow from upper to lower. Hydrogen-steam releases from a small break are simulated, and two nozzle locations have been used. A number of gas sample, air velocity, and temperature measurement locations are concentrated in the annular lower compartment. Initial tests with thermal gradients and scaled recirculation flow, without injected hydrogen or steam, indicate that normal air flow velocities are about 3–15 m/min.

An early test with a jet of helium-steam used as a simulant for hydrogen-steam showed that very good mixing existed in the lower compartment. Other experiments systematically examined the effects of high and low source flow, with and without the forced convection system.

The small- and intermediate-scale experiments now well under way will be followed by a large-scale demonstration project at DOE's Nevada Test Site to study the operation of selected hydrogen control methods and to determine scaling relationships for turbulent hydrogen combustion phenomena. The Nevada facility will simulate potential accident environments with steam, sprays, safety-related equipment, and structures.

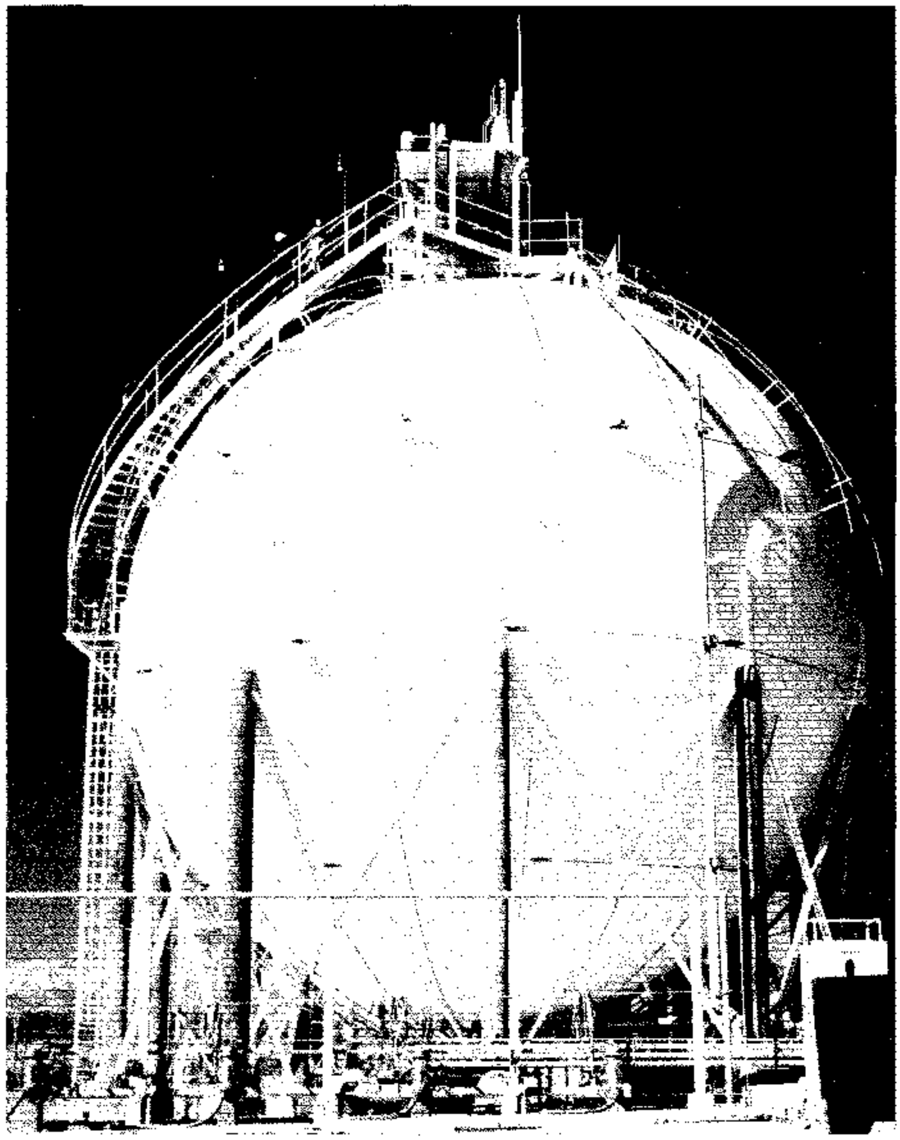
Figure 3 shows the Nevada dewar, which has an inner diameter of 16 m, an annulus of 1 m between inner and outer shells, and a design pressure of 700 kPa (abs) (102 psi) with 100 kPa (15 psi) in the annulus. The project has been initiated with facility renovation and modification activities and with preliminary design of the data acquisition system. Holmes & Narver, Inc., Reynolds Electric Co., and EG&G, Inc., are involved as principal subcontractors. Tests will include dynamic simulations of degraded core accidents, effects of containment sprays, steam, compartments, turbulence and structures, initial pressure (including subatmospheric for greater safety margins), and safety-related equipment. When combined with the Whiteshell results in 0.002-, 0.017-, and 6-m^3 volumes and the Acurex results in an 18-m^3 volume, the 2100-m^3 Nevada experiment will provide a maximum range factor of 1,000,000 in volume and 100 in linear dimension for the establishment of scaling laws.

Factory Mutual is developing models for the combustion of lean and rich mixtures and is assisting in the analysis of data from the various combustion tests. In the case of lean mixtures, the combustion is incomplete, nonadiabatic, and governed by buoyant flame propagation. In the case of rich mixtures, the combustion is complete and adiabatic, and it involves nearly spherical flame propagation.

An early version of the complete combustion model has been prepared that accurately predicts peak combustion pressures. Pressure-rise times are more difficult to predict. The incomplete combustion model requires consideration of burn-back after the flame contacts the top of a vessel, plus changes in flame shape and heat losses during the rise stage.

Battelle is currently evaluating the ability of the TEMPEST code to predict hydrogen distribution data. TEMPEST is a three-dimensional hydro-thermal code that solves the time-dependent momentum, continuity, energy conservation, and turbulence transport equations. The code appears to predict some German hydrogen distribution data reasonably well, although more comparisons with the data are needed before firm conclusions can be stated. The ability of TEMPEST and several other codes to predict the HEDL mixing and distribution data will be examined in 1982. Standard problems are being formulated, and the test results will be withheld until blind calculations can be made and registered by several groups. In this way the state of the art can be more accurately defined, and needed modeling improvements can be identified.

Figure 3 Dewar at DOE's Nevada Test Site for demonstration experiments on hydrogen combustion and control.



A large data base is being generated for the mixing and combustion behavior of hydrogen in severe accident environments. Results to date in small- and intermediate-scale vessels indicate that the deliberate ignition method of hydrogen control is viable and effective. Issues in need of resolution include large-scale mixing behavior, predictive capabilities for mixing and combustion, and demonstration that the lessons learned apply also to much larger scale and can indeed be extrapolated to nuclear reactor containments. *Project Manager: Loren Thompson*

VIPRE THERMAL–HYDRAULIC ANALYSIS CODES

Thermal-hydraulic codes are required by nuclear power utilities to analyze core performance in PWRs and BWRs under a wide range of operating conditions and moderate *transients. There are only a few publicly available computer codes that can be applied to these types of analyses (mainly, the COBRA family of codes). These codes were not specifically designed for the requirements of the utilities, nor were they adequately qualified and documented. Under RP1584-1 the VIPRE codes (versatile internals and components programs for reactors–EPRI) are being developed from the best of the existing COBRA codes. VIPRE will provide the utilities with PWR and BWR core thermal-hydraulic analysis capabilities tailored to their specific needs.*

VIPRE-1 is a homogeneous code designed for general-purpose thermal-hydraulic analysis in normal operating conditions, operational transients, and events of moderate severity. VIPRE-2 is a two-fluid code that will have the same overall capabilities as VIPRE-1, and it can also be used for steam generator analysis.

VIPRE-1

VIPRE-1 was developed on the strengths of the COBRA code series, most notably codes COBRA–IIIC, COBRA–IIIC/MIT, and COBRA–IV-I, with valuable improvements to flow solution numerics adapted from COBRA–WC. A large part of the development work on VIPRE-1 consisted of tailoring the code to the utilities' analytic requirements, upgrading the code's capabilities, and improving the flexibility of its use. Some of the more important improvements were the following.

- Expanded choice of correlations for critical heat flux (CHF), including the new EPRI-1 methodology, critical power ratio (CPR), two-phase flow and heat transfer, and provision for user-programmed correlations in each category
- Several input options tailored for one-pass hot-channel analysis
- Iteration capability for set-point analysis
- Ability to vary the shape of the fuel rod axial power profile during transients
- Generalized rod conduction model for nuclear fuel rods, electric heater rods, hollow tubes, and walls. (A dynamic gap conductance model is available with nuclear fuel rods.)
- Capability to compute flow reversal and recirculation
- Compact storage scheme and several flow solution options
- Free field input
- Output options for line printer plots and a postprocessor for CALCOMP plots
- Implemented functional fits of water properties

These new features not only make VIPRE-1 flexible and easy to use but also enable it to perform many simulations that current codes cannot. VIPRE-1 predicts the three-dimensional velocity, pressure, and thermal energy fields for single- and two-phase flow in PWR and BWR cores. It solves the finite difference equations for mass, energy, and momentum conservation for an interconnected array of channels, assuming incompressible homogeneous flow. The equations are solved with no time-step or channel-size restrictions for stability. Although the formulation is homogeneous, nonmechanistic models are included for subcooled boiling and vapor/liquid slip in two-phase flow.

Like most other core thermal-hydraulic codes, the VIPRE-1 modeling structure is based on subchannel analysis. The core or section of symmetry is defined as an array of parallel flow channels with lateral connections between adjacent channels. A channel may represent a true subchannel within a rod array, a closed tube, or a larger flow area representing several subchannels or rod bundles. The shape and size of the channels and their interconnections are essentially arbitrary. The user has a great deal of flexibility for modeling reactor cores or any other fluid flow geometry.

A particularly useful application of this flexibility is the ability to do one-pass hot-channel analysis for PWRs (Figure 4). The hottest region of the hot assembly is modeled in great detail with individual subchannels; the remainder of the hot assembly is modeled by lumped channels that compose a larger segment of the rod array. The remainder of the core is modeled on an increasingly coarser mesh, with very large channels made up of several fuel assemblies. This technique is probably the most efficient and realistic way to simulate a reactor core. VIPRE-1 has been designed to easily accommodate this generalized core geometry model through flexible, user-selected input options.

VIPRE-1 can also be used for BWR analysis on a lumped-channel basis, where each bundle is treated as a one-dimensional flow channel. This approach is useful for CPR analysis in a BWR core because the CPR correlations are generally correlated to the bundle-average conditions. The axial distribution of the bundle-average void fraction in the hot bundle is also a parameter of interest in BWR analysis and can readily be calculated with VIPRE-1.

In addition to its independent application, VIPRE-1 is also an important part of the EPRI reactor analysis support package (RASP). VIPRE-1 will compute the detailed flow field in the core by using boundary conditions from the RETRAN systems code and power distributions from the ARMP

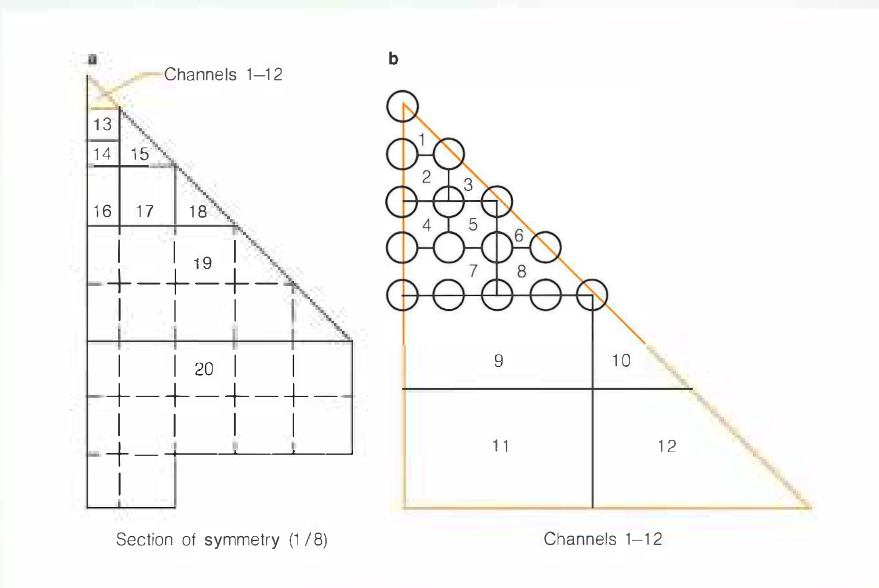


Figure 4 Typical nodalization for a one-pass hot-channel analysis. **(a)** is the subchannel representation of the eighth-symmetry of a BWR core. **(b)** is the detailed subchannel representation of the hot assembly.

VIPRE WORKING GROUP MEMBERS

Arizona Public Service Co.
Consumers Power Co.
Duke Power Co.
Florida Power & Light Co.
GPU Service Corp.
Houston Lighting & Power Co.
Long Island Lighting Co.
Middle South Services, Inc.
Northern States Power Co.
Philadelphia Electric Co.
Power Authority of the State of New York
Public Service Electric and Gas Co.
Southern California Edison Co.
Tennessee Valley Authority
Texas Utilities Services, Inc.
Union Electric Co.
Virginia Electric and Power Co.
Washington Public Power Supply System

neutronics package. Input will be passed between them by linkage programs, but the codes themselves will run independently. As far as practical, VIPRE-1 contains similar empirical correlations and logic to make it consistent with RETRAN for this application.

The initial development and some limited verification work on VIPRE-1 was completed in May 1981. The code was prereleased to the 18 utilities who formed the VIPRE-1 working group. In July a three-day workshop was presented at Battelle, Pacific Northwest Laboratories to acquaint the working group with VIPRE-1. The working group is assisting in the development by performing typical analyses on their plants and some additional verification calculations. This is proving to be an invaluable aid in debugging the code, identifying needed additional capabilities, detecting errors in the documentation, and building a body of practical experience.

Although more work remains, the code has been verified against a wide variety of experimental data for conditions relevant to its intended application. These include void fraction data for subcooled and saturated boiling, heat transfer experiments over the entire boiling curve, a large body of CHF data, and single-phase velocity measurements around blockages in rod bundles. Sensitivity studies investigated the effect of different correlations, variations in geometric detail, time-step size, and solution convergence parameters. The results of most of these tests confirmed that the code performs accurately and efficiently in a wide variety of situations.

One particular application of VIPRE was a steady-state CHF analysis of an entire PWR core with 200 flow channels, each representing a fuel bundle. This application required the equivalent of about 30 seconds of computation time on CDC 7600 or IBM 360 computers. Much larger problems would appear to be feasible with VIPRE-1.

The utility working group is applying the code to models of their specific plants. The results thus far have compared favorably to vendor FSAR calculations and the utilities' previous work with the COBRA codes. Users have found the code easy to use and are able to construct relatively complex models without a great deal of effort.

Further improvement of VIPRE-1's BWR modeling capabilities are under way. This involves installing a more realistic model to compute the bypass flow between bundles. A number of input and output modifications are also being added to make VIPRE-1 fit more easily into RASP.

VIPRE-2

VIPRE-2 is an advanced two-fluid version of VIPRE-1 that is being developed. The basic two-fluid model in VIPRE-2 is being adapted from the steam generator analysis code developed under RP1121. This code was designed to model once-through or U-tube PWR steam generators, including the primary tubes, downcomers, and separator. It can also examine a smaller segment of the steam generator in very close detail and can resolve the individual phase velocity and temperature profiles within a single subchannel. VIPRE-2 will have these capabilities in addition to those of VIPRE-1.

The VIPRE-2 two-fluid model computes the three-dimensional velocity and temperature fields of each phase separately, as well as the local pressures and vapor volume fractions. It uses essentially the same subchannel analysis techniques as VIPRE-1. The two-fluid model computes the relative phase motion and nonequilibrium directly, rather than through correlations for subcooled voids and slip, as required in VIPRE-1. The interaction of the two phases is computed by empirical models for interfacial drag, heat transfer, and mass exchange.

VIPRE-2 is in the initial stages of development. The two-fluid model has been installed in the VIPRE-1 framework. A major effort will be to enhance the speed and reliability of the numerical solution. At present the steady-state simulations can become quite time-consuming and impractical. One goal is to remove the time-step limitation completely so direct steady-state calculations can be performed efficiently. Additional work will involve making the present VIPRE-1 CHF, CPR, and heat transfer correlations compatible with the two-fluid model. The interfacial drag and vapor generation models will also be improved. VIPRE-2 will be prereleased to a utility working group before final release. *Project Manager: J. A. Naser*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP411-5	Evaluation of Two-Stage Liquefaction Concepts	1 year	179.6	Catalytic, Inc. *N. Hertz*
RP1187-8	High-Reliability Gas Turbine–Combined-Cycle Development	7 months	70.0	Arinc Research Corp. *R. Duncan*
RP1270-2	Gas Turbine Modification and Testing for Solar-Fossil Hybrid Operation	4 months	36.0	Solar Turbines, Inc. *J. Bigger*
RP1601-1	Coal Performance Tests: 600-t/d KILnGAS Coal Gasification Pilot Plant	35 months	5750.0	Allis-Chalmers Corp. *J. McDaniel*
RP2094-1	Coal Performance Tests: Coal Gasification Pilot Plant	11 months	500.0	Shell Oil Co. *G. Quentin*
Coal Combustion Systems				
RP979-13	Evaluation of Disk Materials for Fluidized-Bed Combustion	6 months	46.9	Babcock & Wilcox Co. *J. Stringer*
RP1179-12	Evaluation of Fly Ash Recycle Effects on Fluidized-Bed Combustion Sulfur Sorption	8 months	51.8	General Atomic Co. *C. Aulisio*
RP1338-5	Capabilities Survey: Coal Combustion Test Facilities	6 months	62.7	Energy Systems Associates *F. Karlson*
RP1689-11	Augmented Heat Transfer Rates in Utility Condensers	20 months	99.6	Empire State Electric Energy Research Corp. *I. Diaz-Tous*
RP1752-1	Development of Human Factor Design Guidelines for Fossil-Fuel-Fired Steam-Generating Systems	20 months	650.7	Honeywell, Inc. *J. Dimmer*
RP1887-3	Guidelines for Maintenance and Operation of Feedwater Heaters	8 months	78.8	International Energy Associates, Ltd. *I. Diaz-Tous*
RP1961-2	Revision of Stearns-Roger Engineering Corp. Interim Continuous Emission Monitor Guideline Manual	4 months	28.0	Kilkelly Environmental Associates *C. Dene*
Electrical Systems				
RP68-9	Seminars: High-Voltage Transmission Line Design	7 months	98.0	General Electric Co. *J. Dunlap*
RP1231-1	Development of a Field-Usable Detector to Measure PCBs in Oil	19 months	295.6	Battelle Memorial Institute, Inc. *V. Tahiliani*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1493-3	Seminars: Transmission Line Foundation	1 year	32.1	Fred Kulhawy, Consulting Engineer *P. Landers*
RP1536-8	Electrification Compatibility Studies	3 months	25.0	General Electric Co. *V. Tahiliani*
RP1952-1	System Separation: System Requirements for Reducing Occurrence and Minimizing Impact	11 months	82.8	Westinghouse Electric Corp. *J. Mitsche*
RP1964-2	Methodology for Integration of HVDC Links in Large AC Systems: Phase 2, Advanced Concepts	27 months	483.7	Institut de Recherche de l'Hydro-Québec *N. Balu*
RP2109-1	Optimization of Volt-Ampere-Reactive Sources in System Planning	18 months	349.9	Scientific Systems, Inc. *N. Balu*
RP2115-3	Evaluation of Low-Resistivity Insulating Material	9 months	44.1	Westinghouse Electric Corp. *V. Tahiliani*
RP2150-1	Fault Location System for HVDC Transmission Lines	11 months	147.5	Washington State University *V. Tahiliani*
RP7801-38	Waltz Mill 100-kVDC Bay Construction: Phase 2, Completion	1 year	126.1	Westinghouse Electric Corp. *J. Shimshock*
RP7876-17	Polysil-Encapsulated Conductors	6 months	35.1	R. Torres & Associates *M. Rabinowitz*
Energy Analysis and Environment				
RP1152-6	Role of Electrification in Productivity Growth	10 months	100.0	Dale W. Jorgenson Associates *V. Niemeyer*
RP1219-9	Adapting the Transportation Network Model for Utility Use	7 months	30.0	Battelle, Columbus Laboratories *E. Altouney*
RP1367-2	Cost Projections: Development of U.S. Natural Gas Potential	28 months	127.7	Gas Research Institute *J. Platt*
RP1485-1	Upgrade of the Load Management Strategy Testing Model	7 months	44.3	Battelle, Columbus Laboratories *V. Niemeyer*
RP1598-1	Feasibility Study: Toxicologic Studies	9 months	167.9	Gordon A. Enk & Associates *B. Smith*
RP1777-2	Technical Assessment: United Technologies Corp. First-Generation Fuel Cell Design	6 months	65.0	Kryos Energy, Inc. *D. Rastler*
RP1947-3	Application of Decision Analysis to Fuel Planning	1 year	86.9	Strategic Decisions Group *S. Chapel*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2174-1	Regional Integrated Lake-Watershed Acidification Studies	45 months	2051.3	Tetra Tech, Inc. *R. Goldstein*
RP2174-90	Cofunding Agreement: Regional Integrated Lake-Watershed Acidification Studies	34 months	1460.0	Empire State Electric Energy Research Corp. *R. Goldstein*

Energy Management and Utilization

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1275-10	Workshop: Textile Industry Electrification	3 months	25.4	Georgia Tech Research Institute *L. Harry*
RP1275-13	Workshop: Materials Fabrication (Process Application Meeting)	6 months	24.5	Battelle, Columbus Laboratories *L. Harry*
RP1677-7	Evaluation of Fuel Cell Commercialization Efforts	1 year	79.3	Energy Transition Corp. *D. Rigney*
RP1745-5	Evaluation and Improvement of Hydro Reliability	19 months	210.1	Motor-Columbus Consulting Engineers, Inc. *C. Sullivan*
RP1967-4	Industrial Robotics, Data Verification Study	6 months	74.8	Science Management Corp. *J. Brushwood*
RP1979-2	Impact of End Use on Transmission and Distribution System	5 months	99.9	Westinghouse Electric Corp. *T. Yau*
RP2033-3	Analysis of Non-Vapor-Compression Heat Pump Cycles	9 months	146.1	Foster-Miller Associates, Inc. *J. Calm*
RP2035-1	Hardware Issues in Residential Load Management	5 months	50.6	Strategies Unlimited *V. Rabl*

Nuclear Power

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP216-3	Support for the Halden Research Program	3 years	517.0	Institute for Energy Technology *A. Roberts*
RP1068-4	Feasibility Study of In Situ Corrosive Salt Deposition Analysis	6 months	49.6	Lockheed Missiles & Space Co., Inc. *T. Passell*
RP1167-7	Mechanisms of Formation and Disruption of Surface Oxides	11 months	194.1	Rockwell International Corp. *D. Cubicciotti*
RP1381-2	Numerical Simulation of Slow Transients in PWRs	16 months	170.8	Jaycor *J. Kim*
RP1395-10	Single-Frequency Eddy-Current Analysis Program	8 months	78.4	Adaptronics *J. Quinn*
RP1544-3	TMI-2 Mechanical Component Recovery Support	13 months	25.0	GPU Service Corp. *G. Sliter*
RP1544-6	Technical Services in Support of the TMI-2 Mechanical Component Information and Examination Program	1 year	75.2	Pentek, Inc. *G. Sliter*
RP1544-7	Site Activities for EPRI TMI-2 Program	1 year	72.4	Pentek, Inc. *A. Roberts*
RP1580-5	Demonstration of 9 × 9 Fuel Assemblies for BWRs	6 months	240.1	Exxon Nuclear Co., Inc. *D. Franklin*
RP1707-7	Radiation Data for Design/Qualification of Nuclear Plant Equipment	9 months	70.0	NASA—Jet Propulsion Laboratory *G. Sliter*
RP1761-8	Reload Code Linkages	10 months	225.0	Technology Development Corp. *L. Agee*
RP1761-10	NODETRAN: A Linkage Code Between EPRI–NODE-P and RETRAN	11 months	65.9	S. Levy, Inc. *W. Eich*
RP1761-11	Calculation of Delayed Neutron Data With ARMP Programs	6 months	29.5	S. Levy, Inc. *O. Ozer*
RP1932-16	Computer Simulation of Hydrogen Distributions	8 months	30.0	Battelle, Pacific Northwest Laboratories *L. Thompson*
RP2012-1	Reactor Coolant System Decontamination of Accident Fission Products	20 months	60.1	Battelle, Pacific Northwest Laboratories *M. Naughton*
RP2055-9	Design and Manufacture of Tooling for Test Material Removal	10 months	120.6	Product and Systems Engineering *T. Marston*
RP2122-2	Engineering Analysis of Thermal-Hydraulics Associated With PWR Thermal Shock	1 year	50.9	Jaycor *B. Sun*
RP2122-4	Half-Scale Testing of Fluid and Thermal Mixing in a Model Cold-Leg and Downcomer	3 months	79.0	Science Applications, Inc. *J. Sursock*
RP2126-1	Scoping Studies for the Development of the Steam Generator/ Feedwater Loop Control System Monitoring Scheme	1 month	30.0	Combustion Engineering, Inc. *S. Divakaruni*
RP2136-1	Volatile Fission Product Release From Irradiated LWR Fuel Under Simulated Accident Conditions	3 years	700.0	Argonne National Laboratory *R. Vogel*
RP2164-1	Clad-Interface Crack Detection and Sizing	10 months	216.3	Sigma Research, Inc. *J. Quinn*
RP2167-1	Survey and Analysis of Work Structure Factors in Nuclear Power Plants	1 year	119.8	BioTechnology, Inc. *H. Parris*
RP2168-1	TMI-2 Technical Evaluation Group on Hydrogen Combustion	8 months	74.9	Factory Mutual Research Corp. *J. Haugh*
RP2171-1	Review of Comprehensive-Scale Probabilistic Risk Assessment Studies	6 months	120.0	NUS Corp. *D. Worledge*

New Technical Reports

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

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

Requests for copies of specific 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, government agencies (federal, state, local), or foreign organizations with which EPRI has an agreement for exchange of information. Others in the United States, Mexico, and Canada pay the listed price. Research Reports Center will send a catalog and complete price list (including foreign prices) on request.

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Microfiche copies are available from National Technical Information Service, P.O. Box 1553, Springfield, Virginia 22151.

ADVANCED POWER SYSTEMS

Direct-Flash Steam Geothermal Power Plant Assessment
AP-2162 Final Report (RP1195-1); $10.50

The 75-MW (e) plant at Cerro Prieto, Mexico, was studied from 1973 to 1979 to determine the significant characteristics of an operating direct-flash geothermal power plant. Details on plant system and component specifications, operating procedures, maintenance history, malfunctions, availability factor, capacity factor, and outage rate are provided. The contractor is Arizona Public Service Co. *EPRI Project Manager: E. E. Hughes*

Assessment of Arid Lands Plants as Future Energy Crops for the Electric Utility Industry
AP-2172-SR Special Report; $10.50

The prospects and problems of using selected native arid lands plants (terpene- and non-terpene-containing species) as future biomass fuel sources for electric power plants are assessed. The processing and production technologies associated with various plant species are described, and R&D recommendations are presented. The contractors are Kennith E. Foster and William H. Brooks. *EPRI Project Manager: S. M. Kohan*

Dynamic Simulation of Sulfur Removal Systems
AP-2187 Final Report (RP1038-2); $12.00

A generalized computer simulation was developed to predict the dynamic response of alternative gas absorption systems for the selective removal of sulfur compounds or ammonia from fuel gas or synthesis gas produced from coal or other fossil fuels. The simulation may be applied to systems based on either chemical or physical principles. The contractor is Systems, Science & Software. *EPRI Project Manager: G. H. Quentin*

Coal Slag Phenomena in MHD Generators
AP-2201 Final Report (RP468-1); $28.50

This report describes an experimental and analytic investigation of coal slag phenomena in magnetohydrodynamic (MHD) generators and discusses its three major accomplishments: development of fundamental data on the formation, behavior, and effects of coal slag on MHD channel walls; development of analytic techniques to predict many slag phenomena; and design and use of diagnostic instrumentation for observing MHD channel slag effects and overall performance. The contractor is Stanford University. *EPRI Project Managers: A. C. Dolbec and P. S. Zygielbaum*

Guide for Assessing the Availability of Gasification–Combined-Cycle Power Plants
AP-2202 Final Report (RP1461-1); $16.50

This guide presents a methodology for predicting the reliability and availability of coal gasification–combined-cycle electric power generation units. The seven-step assessment methodology yields predictions of such performance measures as unit effectiveness, availability, equivalent availability, and forced-outage rate. Application of the methodology to a 1150-MW baseload plant is described. The contractor is Arinc Research Corp. *EPRI Project Manager: Jerome Weiss*

Component Failure and Repair Data: Gasification–Combined-Cycle Power Generation Units
AP-2205 Topical Report (RP239-2); $15.00

Failure rates and average restoration times for generic types of equipment for a coal gasification–combined-cycle power plant were developed by using published EEI data, a failure modes analysis approach, and expert consensus methods. The material is intended for use as input in assessing the reliability and availability of a representative plant. The contractor is Fluor Engineers and Constructors, Inc. *EPRI Project Manager: Jerome Weiss*

Coal Gasification–Combustion Turbine Power Plants Emphasizing Low Water Consumption
AP-2207 Final Report (RP986-8); $22.50

This report describes a study to develop conceptual designs, performance data, capital and operating cost estimates, and busbar power costs for six different configurations of coal gasification–combustion turbine power plants, some employing air cooling. The results indicate that air-cooled configurations would be cost-competitive with water-cooled conventional plants and moderately more costly than water-cooled coal gasification–combined-cycle plants. The contractor is The Ralph M. Parsons Co. *EPRI Project Manager: B. M. Louks*

Coproduction of Methanol and Electricity With Texaco Gasification–Combined-Cycle Systems
AP-2212 Final Report (RP239-2); $19.50

This economic evaluation examines process options and costs for the coproduction of methanol by the once-through method in a baseload gasification–combined-cycle (GCC) power plant. It reviews two plant designs: a standard Texaco-based GCC plant and a similar Texaco-based GCC plant incorporating a Chem Systems liquid-phase methanol synthesis system. The contractor is Fluor Engineers and Constructors, Inc. *EPRI Project Managers: E. L. Force and M. J. Gluckman*

Enriched-Air and Oxygen Gasification of Illinois No. 6 Coal in a Texaco Coal Gasification Unit
AP-2214 Interim Report (RP985-1); $7.50

Four runs were made with Illinois No. 6 coal to demonstrate technology for integrating the Texaco coal gasification process in an environmentally acceptable manner with gas turbines for combined-cycle electric power generation. The operability and response of the gasifier and a Selexol acid gas removal unit during load changes (with both oxygen and enriched air used as oxidants) were evaluated. Steady-state performance data on the gasifier, Selexol unit, and gas turbine combustor are included. The contractor is Texaco, Inc. *EPRI Project Manager: John McDaniel*

Low-Activation Structural Materials for Fusion Reactors: Extreme-Purity Base Aluminum Alloys
AP-2220 Final Report (RP1045-1); $13.50

This report describes a study of extreme-purity base aluminum alloys. Initial data on experimental alloys containing low-activity alloying elements (silicon and vanadium) are included. It was concluded that high-purity, low-activity powder metallurgy aluminum alloys can be developed for use in fusion reactors at 300–400°C. The contractor is Alcoa Technical Center. *EPRI Project Managers: K. W. Billman and W. T. Bakker*

High-Reliability Gas Turbine Combined-Cycle Development Program: Phase 2
AP-2226 Final Report (RP1187-1); Vol. 1, $13.50; Vol. 2, $25.50; Vol. 3, $22.50

This report documents Phase 2, the preliminary design phase, of a program to achieve a high-reliability gas turbine combined-cycle power plant for baseload generation. Volume 1 summarizes the results. Volume 2 presents background analyses; a reliability, availability, and maintainability analysis; and the preliminary designs for the gas turbine, the gas turbine auxiliary equipment, and the balance of plant. Volume 3 defines the R&D program requirements, describes alternative fuels and retrofit analyses, and presents gas turbine design criteria. The contractors are United Technologies Corp. and Pratt & Whitney Aircraft. *EPRI Project Manager: R. L. Duncan*

1980 Operation of SRC Pilot Plant, Wilsonville, Alabama

AP-2235 Annual Report (RP1234-1-2); $16.50

This report summarizes the operating conditions and results of test runs during 1980 at the 6-t/d solvent-refined coal (SRC) pilot plant in Wilsonville, Alabama, a project cosponsored by DOE and EPRI. It reviews experiments conducted to evaluate potential process improvements; four major process studies in the SRC section; and a series of simulation runs to investigate design operating conditions for a planned 6000-t/d SRC demonstration plant. The contractor is Southern Company Services, Inc. *EPRI Project Manager: H. E. Lebowitz*

Agglomeration of SRC Residues

AP-2236 Final Report (RP1606-1); $7.50

Kerr-McGee Corp.'s critical solvent de-ashing ash concentrate was agglomerated, and the agglomerate's suitability as feed for fixed-bed gasifiers was investigated. Briquettes produced from three sample ash concentrates were tested under handling and firing conditions, and their CO_2-carbon reactivity values were determined. The contractor is Conoco Coal Development Co. *EPRI Project Manager: H. E. Lebowitz*

Liquid- and Solid-Waste Management for Coal Conversion Processes

AP-2245 Final Report (RP1658-02); $15.00

This report presents a technical assessment of pollution control technology for liquid and solid wastes that are expected from coal conversion processes. Treatment schemes for four typical liquefaction and gasification processes are detailed: Lurgi fixed-bed gasification, Texaco entrained-bed gasification, H-Coal direct liquefaction, and Exxon Donor Solvent direct liquefaction. Analytic methods applicable to coal conversion waste streams are reviewed, and the potential for stricter environmental standards is assessed. The contractor is Olympic Associates Co. *EPRI Project Manager: W. S. Reveal*

Utility Requirements for Fusion

AP-2254 Topical Report (RP1413-1); $13.50

Utility requirements and criteria for fusion options were defined and ranked to aid in R&D planning and decision making. This report presents the requirements and describes the questionnaire-workshop approach used in determining them. The contractor is Burns and Roe, Inc. *EPRI Project Manager: N. A. Amherd*

COAL COMBUSTION SYSTEMS

Preliminary Economic Analysis of NO_x Flue Gas Treatment Processes

CS-2075 Final Report (RP783-3); $19.50

Results are presented from a preliminary-level economic evaluation to compare seven flue gas treatment processes for removing NO_x from power plant flue gas. Capital investment and annual revenue requirement estimates were made on the basis of Tennessee Valley Authority (TVA) design premises and two sets of economic premises, one developed by EPRI and one by TVA. The contractor is TVA. *EPRI Project Manager: J. E. Cichanowicz*

Solidification of Low-Volume Power Plant Sludges

CS-2171 Final Report (RP1260-20); $9.00

A literature review was conducted to obtain state-of-the-art information on hazardous waste solidification technology and its application to low-volume power plant waste sludges. Low-volume waste characteristics are identified, and eight solidification processes with potential application to low-volume sludges are described. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: D. M. Golden*

Recommended Procurement Guidelines for Pulverizers in Large Steam-Generating Units

CS-2179 Final Report (RP1265-1-1); $13.50

These guidelines, prepared to aid in pulverizer specification and procurement, address areas of performance that have significant impact on mill system operation and maintenance: redundancy, reliability, durability, replaceability, accessibility, visibility, maintainability, and safety. The report discusses large-scale mill configurations and operation; pulverizing capability design data; mill technical data; codes and performance; and testing, instrumentation, and examination. The contractor is KVB, Inc. *EPRI Project Manager: I. A. Diaz-Tous*

Adipic Acid Addition to a Bench-Scale Chiyoda Thoroughbred-121 FGD System

CS-2185 Final Report (RP536-5); $9.00

This report presents the results of a laboratory study conducted to evaluate the effectiveness of adding adipic acid to the Chiyoda Thoroughbred-121 flue gas desulfurization system to enhance SO_2 removal capabilities. Economic calculations performed to evaluate the cost-effectiveness of using adipic acid in a commercial-scale system are included. The contractor is Radian Corp. *EPRI Project Manager: T. M. Morasky*

Pelletization of Fine Coals

CS-2198 Final Report (RP1030-1); $12.00

This report describes a project to develop a process engineering basis for the pelletization of coal fines. Effects of size consist, feed moisture content, residence time, and binder addition on the size distribution and strength of the pellets are discussed. The results indicate that the pelletization of coal fines is highly feasible. The contractor is the University of California at Berkeley. *EPRI Project Managers: R. S. Sehgal and K. L. Clifford*

Symposium Proceedings: Power Plant Fans—State of the Art

CS-2206 Proceedings (WS81-194); $37.50

This report presents the proceedings of a symposium on the state of the art of power plant fans and draft systems that was held in October 1981 in Indianapolis, Indiana. It includes papers on fan design; fan system design; fan selection and application; and fan operation, maintenance, and diagnostics. The contractor is Fan Systems Co. *EPRI Project Manager: I. A. Diaz-Tous*

Spray-Dryer Flue Gas Desulfurization

CS-2209 Final Report (TPS80-741); $10.50

A study was conducted to define the status of utility spray-dryer flue gas desulfurization in the United States. The report surveys the 12 vendors currently in the market, details the pertinent design features of the 13 utility systems contracted through September 1981, and reviews the status of the technology. Recommendations are made for test work to advance the understanding of the process and to extend the range of applicability to higher-sulfur coals. The contractor is Stearns-Roger Engineering Corp. *EPRI Project Manager: R. G. Rhudy*

Engineering Assessment of an Advanced Pulverized-Coal Power Plant

CS-2223 Final Report (RP1403-1); $37.50

This report presents the results of an engineering study to evaluate the cost-effective performance potential available through improvements in conventional pulverized-coal-based power plant design. A conventional cycle featuring throttle steam at 4500 psi and 1100°F, two reheats (each with 1050°F steam), recovery of waste energy for air preheat and flue gas reheat, and modest improvements in equipment design was determined to be desirable and achievable. The contractor is Westinghouse Electric Corp. *EPRI Project Managers: D. V. Giovanni and A. F. Armor*

Proceedings: First Conference on Fabric Filter Technology for Coal-Fired Power Plants

CS-2238 Proceedings (WS81-206); $36.00

This report contains 18 papers presented at a conference on fabric filter technology that was held in July 1981 in Denver, Colorado. The papers describe the latest developments in the design and operation of fabric filters for coal-fired utility boilers. Topics include weaving, finishing, and fabrication of bags; full-scale and pilot plant evaluations; and advanced fabric filter concepts. A discussion of fabric filter operating experience by utility representatives is also presented. *EPRI Project Manager: R. C. Carr*

Temper Embrittlement of CrMoV Turbine Rotor Steels

CS-2242 Interim Report (RP559); $9.00

Samples from the hot and cold ends of two retired CrMoV steam turbine rotors of 1950 vintage (Joppa No. 3 and Buck No. 6) and the failed Gallatin rotor were studied with respect to the degree of temper embrittlement, fracture mode, impurity segregation, and microstructure in the as-received condition and after various heat treatments. The results support the generally held view that CrMoV high-pressure-rotor steels are less susceptible to temper embrittlement than NiCrMoV low-pressure-rotor steels. The contractor is the University of Pennsylvania. *EPRI Project Manager: Ramaswamy Viswanathan*

Recommended Guidelines for the Admission of High-Energy Fluids to Steam Surface Condensers

CS-2251 Final Report (RP1689-1); $15.00

This document is a design guide to aid in the development of voluntary standards for both users and manufacturers of steam surface condensers serving large steam turbine generators. It provides engineering design and application information relative to the effective disposition of high-energy fluid admissions to steam condensers, exclusive of the main turbine exhaust steam. The contractor is Gilbert Associates, Inc. *EPRI Project Manager: I. A. Diaz-Tous*

ELECTRICAL SYSTEMS

Development of Extruded Dielectric Underground Transmission Cables Rated 138 kV, 230 kV, and 345 kV
EL-428 Final Report, Vol. 2 (RP7829-1); $19.50
This report covers the continuation of work to develop technology for manufacturing chemically cross-linked polyethylene-insulated power cables in the ac voltage range of 138–345 kV with insulation thicknesses approximately equal to that of oil-impregnated paper-insulated cables. Work to develop field-molded splices and terminations for new high-voltage stress 138-kV cables is also described. The contractor is GK Technologies, Inc. *EPRI Project Manager: F. G. Garcia*

Development of a Circuit Breaker for Large Generators
EL-2195 Final Report (RP1501-1); $16.50
Design concepts for the development of circuit breakers for large generators were evaluated, and a rating structure for a generator circuit breaker was defined. Design requirements are presented for SF_6 synchronous and nonsynchronous interrupters of the axial-flow type, and a concept for a current-limiting generator circuit and two variations of that concept (frangible conductors and a liquid metal impedance device) are reviewed. The contractor is Gould–Brown Boveri, Inc. *EPRI Project Manager: N. G. Hingorani*

Development of Low-Loss 765-kV Pipe-Type Cable
EL-2196 Final Report (RP7812-1); $13.50
This report documents the development and testing of a low-loss, high-pressure 765-kV pipe-type transmission cable and splice employing an oil-impregnated polypropylene laminate insulation. An analysis of cable failures is presented, as well as a comparative economic evaluation of polypropylene-insulated and cellulose-insulated systems. The contractor is Phelps Dodge Cable & Wire Co. *EPRI Project Manager: J. F. Shimshock*

Laterally Loaded Drilled-Pier Research
EL-2197 Final Report (RP1280-1); Vol. 1, $13.50; Vol. 2, $24.00
Volume 1 is a user's manual for PADLL (pier analysis and design for lateral loads), a computer program based on a semiempirical model. The design methodology, PADLL documentation, techniques for determining the subsurface information required by PADLL, and design recommendations are presented. Volume 2 documents the research that led to the PADLL design methodology. The contractor is GAI Consultants, Inc. *EPRI Project Manager: Phillip Landers*

Workshop Proceedings: Rotating Machinery Insulation
EL-2211 Proceedings (WS81-182); $19.50
This report contains the proceedings of a workshop on rotating machinery insulation held in September 1981 in St. Louis, Missouri. The workshop focused on the practical problems faced by utilities in reducing the number and severity of insulation-related problems and in testing the suitability of their machines' insulation systems for continued operation. The contractor is A. W. W. Cameron. *EPRI Project Manager: J C. White*

Parallel Multiarea State Estimation
EL-2218 Final Report (RP1764-1); $10.50
This report describes state estimation, the mathematical analysis used to estimate the state (voltage magnitudes and angles) of an electric power system. The problem of static state estimation is addressed; and proposed improvements, Newton's method, power system decomposition, and minimization of the error function are detailed. The contractor is Washington University. *EPRI Project Manager: C. J. Frank*

High-Ampacity Terminations
EL-2233 Final Report (RP7857-1); $16.50
A variety of cooling methods for increasing pipe-type cable termination ampacities were tested for both existing and new cable installations from 69 to 500 kV. An analysis using two computer methods (a network method and a matrix method) was performed on the heat transfer process in typical cable termination designs. Final versions of the improved and verified computer models are included. The contractor is G&W Electric Specialty Co. *EPRI Project Manager: J. F. Shimshock*

Fault Analysis in Gas-Insulated Equipment
EL-2248 Final Report (RP1360-1); $18.00
This report presents the results of a project to develop new techniques for detecting and locating faults in totally enclosed SF_6-gas-insulated substation equipment. The project investigated an insulated-tape method (which was found to be unsuitable); a technique using an infrared camera and a video recording system; and a temperature-sensitive paint. Testing to study the behavior of an arc in SF_6 gas was also conducted. The contractor is Ontario Hydro. *EPRI Project Manager: V. H. Tahiliani*

Fault Detection Sensors for Gas-Insulated Equipment
EL-2249 Final Report (RP1360-2); $19.50
This report describes research to develop new techniques for detecting and locating faults or internal insulation degradation in totally enclosed SF_6-gas-insulated substation equipment, particularly the coaxial conductors used extensively in EHV and UHV substations. The development of three types of sensors—thin film (chemical), optical, and magnetic—is discussed. The contractor is General Electric Co. *EPRI Project Manager: V. H. Tahiliani*

Determination of AC Conductor and Pipe Loss in Pipe-Type Cable Systems
EL-2256 Final Report (RP7832-2); $13.50
This report presents the results of work on the determination of the ac/dc resistance ratios of HV and EHV pipe-type cables with conventional and large-size segmental conductors in carbon steel, stainless steel, and aluminum pipes. Configurations with three cables per pipe and a single cable per pipe were studied. The contractor is Pirelli Cable Corp. *EPRI Project Manager: F. G. Garcia*

DC Conductor Development
EL-2257 Final Report (RP1514); $13.50
This report describes the conceptual development of promising conductors and line configurations for HVDC overhead transmission lines. It details analytic and experimental work conducted to determine the performance of the proposed concepts and ranks the most promising concepts. The contractors are Alcoa Conductor Products Co. and General Electric Co. *EPRI Project Manager: J. H. Dunlap*

Distribution Vacuum Arc Fault Current Limiter
EL-2266 Final Report (RP1140-1); $13.50
This project demonstrated the feasibility of using a vacuum arc as the basis for a distribution class fault current limiter. The device tested involved a vacuum arc between a hollow cylindrical anode and a short rod cathode located on the axis of the anode. Two modes of operation were investigated. It was concluded that the vacuum arc with applied axial magnetic field was the more suitable mode for use as a commutating switch for a switched resistor fault current limiter. The contractor is McGraw Edison Co. *EPRI Project Manager: R. S. Tackaberry*

ENERGY ANALYSIS AND ENVIRONMENT

Power Plant Chlorination: Biological and Chemical Assessment
EA-1750 Final Report (RP1312-1); $21.00
An assessment of literature on chlorine chemistry and toxicity is presented, along with research recommendations based on the review. Chlorine reaction rates and paths, chemical species, oxidant analyses, and organic products are detailed, and freshwater, estuarine, and marine toxicity methodologies are described. The contractor is the Academy of Natural Sciences of Philadelphia. *EPRI Project Manager: J. W. Huckabee*

Assessment of the Legislative and Regulatory Environment: NO_x Case Studies
EA-2063 Topical Report (RP1375); $9.00
This report—a supplement to Volume 2 of EA-2048, *Control of Nitrogen Oxides: Assessment of Needs and Options*—presents six California case studies that illustrate many of the NO_x-related regulatory issues that can impact fossil fuel power plants. Topics include siting considerations, acquiring and applying emissions offsets, the choice of NO_x control technologies, and interactions among regulatory agencies. The contractor is Systems Applications, Inc. *EPRI Project Manager: R. E. Wyzga*

Decision Framework for Technology Choice
EA-2153 Interim Report (RP1433-1); Vol. 1, $21.00; Vol. 2, $10.50
This report details the technology choice model (TCM), designed to help utility management evaluate and integrate critical elements and uncertainties in problems of technology choice. Volume 1 describes a coal-nuclear application and discusses how TCM can be adopted to a broad range of issues. Volume 2, a user's manual, provides a complete listing of the computer code. The contractor is Woodward-Clyde Consultants. *EPRI Project Manager: R. G. Richels*

Environmental and Safety Assessment of Five Battery Energy Storage Systems
EA-2157 Final Report (RP1317-1); $18.00
This report provides environmental and safety assessments of five battery energy storage sys-

tems: lead-acid, zinc chloride, zinc-bromine, sodium-sulfur, and lithium–metal sulfide. Details on the regulatory framework of the state of California as it would apply to a generic or base case battery system are presented, along with a site selection reference system and a public perception case study. The contractor is Bechtel National, Inc. *EPRI Project Manager: P. F. Ricci*

Survey of the Impacts of Voluntary Load Appeals in the PG&E Service Territory

EA-2158 Final Report (TPS79-755); $7.50

This report describes a study undertaken in connection with efforts to estimate the impacts of electricity shortfalls. The responses of major industrial electricity customers in one utility service area to emergency appeals to reduce demand are examined. The replies indicate extensive variation among firms in their preparation for, and responses to, such appeals. The contractor is Systems Control, Inc. *EPRI Project Manager: R. E. Wyzga*

Forecasting In-Plant Electricity Generation in the Industrial Sector, 1980–2000

EA-2163 Final Report (RP942-1); $22.50

This report presents the results of a study to develop a model for forecasting the use of purchased and self-generated electricity in the industrial sector. The model is described, and forecasts are presented for five industrial categories: paper, chemicals, petroleum refining, primary metals, and all other manufacturing. The contractor is Mathtech, Inc. *EPRI Project Managers: L. J. Williams and S. D. Braithwait*

Load Data Management and Analysis

EA-2178 Final Report (RP1588-2, -3); $15.00

This report presents the results of two studies on load data management and analysis. A survey of existing practices was undertaken, as well as a review of commercially offered software and hardware (data-gathering) systems. The report discusses the major technical issues involved in managing load research data and describes the hardware, software, and personnel requirements for performing the load research function in a variety of utilities. The contractors are Stone & Webster Management Consultants, Inc., and Applied Energy Research, Inc. *EPRI Project Manager: Edward Beardsworth*

Models for Investment and Disinvestment Decision Making Under Uncertainty

EA-2204 Final Report (RP1220-2); $18.00

This report reviews the theoretical framework for decisions regarding investment, disinvestment, and use of durable assets under conditions of uncertainty. Existing models are examined, and new models for evaluating investments and replacements are suggested. The development of a general simulation model and its testing with an actual utility investment decision are described. The contractor is Michigan State University. *EPRI Project Manager: A. N. Halter*

Nitrogen Oxide Transformations in Power Plant Plumes

EA-2217 Interim Report (RP1369-1); $15.00

This report describes laboratory research on the chemical transformations that nitrogen oxides might undergo after emission from fossil fuel power plants. The results indicate that the conversion of NO to NO_2 in the near-field plume is dominated by the ambient O_3 concentration. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: G. R. Hilst*

Doppler Acoustic Sounding: Observational Inputs to Pollutant Dispersion Models

EA-2219 Final Report (RP1622-1); $12.00

This report evaluates the use of the Doppler acoustic system to provide meteorological inputs needed for models simulating the dispersion of effluents from large power plants. The operation of the system is described, and remote measurements of horizontal and vertical wind velocity made with it are compared with measurements made with conventional instrumentation on a 300-m tower. The contractor is Aerovironment, Inc. *EPRI Project Manager: G. R. Hilst*

Socioeconomic Impacts of Power Plants

EA-2228 Final Report (RP1226-4); $19.50

This report presents an assessment of the socioeconomic impacts of power plant construction and operation. The project involved retrospective case studies of 12 plants. Impact assessment models were reviewed; projected construction employment was compared with actual employment; and secondary economic impacts, housing demand and supply, and local government fiscal impacts were assessed. The contractors are the Denver Research Institute and Browne, Bortz & Coddington. *EPRI Project Managers: R. E. Wyzga and A. N. Halter*

Integrated Environmental and Safety Assessment of Selected Mechanical Energy Storage Systems

EA-2231 Final Report (RP1317-2); $24.00

Two mechanical storage systems—compressed-air energy storage and underground pumped hydro—were examined from an environmental point of view. Topics discussed include the safety, socioeconomic, and environmental impacts of these systems; a methodology for site selection; legislation and regulation applicable to the two technologies; an environmental monitoring plan; and the effect of public perception on the acceptability of the two systems. The contractor is NUS Corporation. *EPRI Project Manager: P. F. Ricci*

Design of a Multiregional Economic Model for Forecasting Electricity Consumption and Peak Load

EA-2232 Final Report (RP1007-2); $18.00

This report presents the design of a general multiregional econometric model of the United States and the design of a regional electricity consumption and demand submodel. The econometric model is intended to provide forecasts of regional population, economic activity by industrial sector, regional wages, and incomes. The electricity submodel is designed to take forecasts of such general economic indicators and produce forecasts of peak load and of relative electricity (kWh) consumption by customer category. The contractor is Wharton EFA Inc. *EPRI Project Manager: L. J. Williams*

Survey of Plume Models for Atmospheric Application

EA-2243 Interim Report (RP1616-9); $15.00

On the basis of a set of criteria dictating specific needs of the utility industry, 30 existing plume models for atmospheric application were identified and analyzed. The formulation and technical attributes of the models were compared, and a subset of models was selected for operational and diagnostic validation with the comprehensive data bases being assembled under the plume model validation project. The contractor is Systems Applications, Inc. *EPRI Project Manager: G. R. Hilst*

Review of Computational Aspects of Planning Models

EA-2255 Final Report (RP1483-1); Vol. 1, $9.00; Vol. 2, $7.50

This report presents the results of an evaluation of the computational efficiency and coding accuracy of computer software for two utility planning models. Volume 1 covers the CRA/EPRI Coal Market Analysis System, and Volume 2 the Regulatory Analysis Financial Model. The contractor is Optimal Decisions. *EPRI Project Manager: S. D. Hu*

ENERGY MANAGEMENT AND UTILIZATION

1980 Survey and Evaluation of Utility Conservation, Load Management, and Solar End-Use Projects

EM-2193 Final Report (RP1940-1); Vol. 1, $22.50; Vol. 2, $31.50; Vol. 3, $27.00

This report presents the results of the 1980 survey of electric-utility-sponsored conservation, load management, and end-use solar energy conversion projects. Volume 1 covers conservation; Volume 2, solar end-use technologies; and Volume 3, load management (communication and load control, thermal energy storage). A summary document presenting the survey highlights and technical and economic evaluations of the technologies is forthcoming. The contractor is Energy Utilization Systems, Inc. *EPRI Project Manager: T. M. Lechner*

Load Leveling on Industrial Refrigeration Systems

EM-2208 Final Report (RP1088); $18.00

This report describes a project to demonstrate the technical feasibility and cost-effectiveness of applying conservation and load management approaches to large, energy-intensive industrial compressor systems. The approaches involved capacity modulation, energy conservation through efficiency improvement, and waste heat recovery. A computer simulation of a model plant's electrical demand was used in evaluating compressor control and operation strategies. The contractors are Applied Energy Systems, Inc., and the University of South Florida. *EPRI Project Manager: I. L. Harry*

Thermal Energy Storage: Cooling Commercial Buildings by Using Off-Peak Energy

EM-2244 Proceedings (RP2036-2); $16.50

This report contains the papers presented at a seminar on the use of off-peak energy to cool commercial buildings that was held in Washington, D.C., in September 1981. Topics include recommended applications (types of buildings and usage patterns), full versus partial storage, ice versus water storage, temperature blending and stratification, and the operating experience of several existing cool storage installations. *EPRI Project Manager: V. A. Rabl*

Solar Heating and Cooling Research Projects: Summary

EM-2272-SR Special Report; $7.50

This report is the second in a series summarizing the major EPRI solar heating and cooling experimental projects. In addition to outlining each project and its purpose, the report describes the solar systems and the performance-monitoring equipment. These projects provide a basis for verifying analytic work to determine the preferred solar system for any given utility service area (i.e., the system that provides the lowest total cost to the consumer and the utility). *EPRI Project Manager: G. G. Purcell*

NUCLEAR POWER

PWR FLECHT–SEASET Steam Generator Separate-Effects Task: Data Analysis and Evaluation

NP-1461 Topical Report (RP959-1); $25.50

This report documents the analysis of data obtained from the separate-effects steam generator tests and describes the steam generator evaluation model. Details are provided on the test facility; run conditions and test results; and an evaluation of replicate runs, single-parameter variations, and tubesheet liquid-phase flow distribution effects. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: K. H. Sun*

BWR Refill-Reflood Program 30°-Sector Experimental Plan

NP-1525 Interim Report, Vols. 2–4 (RP1377-1); $10.50

This report presents the experimental task plan for the CCFL/refill system effects tests (30° sector) of the BWR Refill-Reflood Program. Volume 2 defines the approach and strategy to be followed in the 30°-sector facility shakedown, including equipment performance tests, an initial set of facility countercurrent flow-limiting tests, and predictions of selected facility phenomena. Volumes 3 and 4 define detailed test matrices for the separate-effects test series and the transient loss-of-coolant simulation tests, respectively. The contractor is General Electric Co. *EPRI Project Manager: Mati Merilo*

PWR FLECHT–SEASET Unblocked-Bundle Forced- and Gravity-Reflood Task: Data Evaluation and Analysis

NP-2013 Topical Report (RP959-1); $31.50

This report documents the analysis of the data obtained from the unblocked 161-rod bundle forced- and gravity-reflooding tests. Fluid flow and heat transfer mechanisms associated with the reflooding phenomena are evaluated, and models that were developed for the calculation of cladding temperatures during the reflooding transient are described. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: K. H. Sun*

Nondestructive Evaluation Program: Progress in 1981

NP-2088-SR Special Report: $33.00

This report, consisting primarily of contractor-supplied progress reports, represents a comprehensive summary of all nondestructive evaluation (NDE) activities under way in EPRI's Nuclear Power Division. The progress reports and summaries present information on the areas of pipes and nozzles, pressure vessels, steam generator tubes, turbines, materials properties measurements, and technology transfer. *EPRI Project Manager: G. J. Dau*

Stress Corrosion Cracking of Alloy 600

NP-2114-SR Special Report; $9.00

This report summarizes the research progress on the stress corrosion cracking (SCC) of Ni-Cr-Fe Alloy 600 made since the well-documented van Rooyen review, which covered work published up to early 1974. This review focuses on the SCC of Alloy 600 in environments relevant to PWR steam generator operation. The environmental, metallurgical, and mechanical variables that control the susceptibility of Alloy 600 to SCC are discussed, and additional research needs are identified. *EPRI Project Managers: R. L. Jones and J. P. N. Paine*

Profilometry for Steam Generator Tube Dent Characterization

NP-2141 Final Report (RPS108-1); $9.00

This report describes the development of two independent means of determining the characteristics of dents in nuclear steam generator tubes due to the corrosion of carbon steel support plates. In one technique, a strain gage profilometer is used to directly measure the radius changes of a dented tube. In the other technique, a silastic molding agent is injected into the dented region to produce a replica of the tube's inner surface. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: G. W. DeYoung*

Heat Transfer Above the Two-Phase Mixture Level Under Core Uncovery Conditions in a 336-Rod Bundle

NP-2161 Final Report (RP1760-1); $10.50

Heat transfer data obtained above the froth level from a 336-rod bundle in PWR core uncovery tests were evaluated and compared with existing heat transfer correlations for core heat-up analysis. Two methodologies for comparing the heat transfer correlations are described, and a recommendation for an appropriate heat transfer model for use in small-break loss-of-coolant accident analyses is presented. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: K. H. Sun*

Thermal-Hydraulic Analysis of the Bypass Flow in Boiling Water Reactors

NP-2164 Final Report (RP1754-3); $13.50

The results of research on the thermal-hydraulic characteristics of the bypass flow in BWRs are presented. Bypass region heat sources, flows, and void distributions were studied. The computer codes FIBWR and COBRA IIIC/MIT-2 were used to estimate bypass flow rates and to determine the magnitude and distribution of voiding in the bypass flows, respectively. The contractor is the Massachusetts Institute of Technology. *EPRI Project Managers: B. A. Zolotar and J. A. Naser*

EPRI–CURL–P Systems Modeling for a Pool-Type Liquid Metal Fast Breeder Reactor

NP-2170 Final Report (RP352-1); $12.00

This report documents the computer program EPRI–CURL–P, which performs transient analysis calculations for pool-type LMFBRs. The use of this systems analysis code (which was modeled after the loop-type reactor code EPRI–CURL–L) to analyze a reactor scram transient for two current pool-type LMFBR designs is described, as well as loss of electric power and power runback transients for one design. The contractor is Cornell University. *EPRI Project Managers: E. L. Fuller and J. A. Naser*

Bolting Problems, Tools, and Practices in the Nuclear Industry

NP-2174 Final Report (TPS79-746); $13.50

This report summarizes several surveys of in-plant methods used by utilities to handle bolting, tension, and closure problems in nuclear power plants. Steam generator manways, turbines, reactor vessel heads, and valves and leaks are covered. The need for specific-application tool development, better training, improved access, and management involvement is discussed. The contractor is Raymond Engineering Inc. *EPRI Project Manager: Michael Kolar*

RETRAN-01: Program for One-Dimensional Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems

NP-2175 Final Report (RP889); $51.00

This report (a revision of EPRI CCM-5, Volume 4) describes the extensive verification and qualification of the RETRAN computer code, which is used for analyzing the thermal-hydraulic responses of nuclear steam supply systems to hypothetical loss-of-coolant accidents and operational transients. The complete analysis from the original report is included, as well as analyses made available by the EPRI System Analysis Working Group and through in-house and contractor effort. The contractor is Energy Incorporated. *EPRI Project Manager: L. J. Agee*

Heavy Water Breeder Conceptual Core Design

NP-2176 Final Report (RP712-1); $13.50

A reference design is presented for a compact, pressurized heavy-water-cooled and -moderated breeder core based on the uranium-plutonium cycle and a seed-blanket concept. The design's evolution and methods of control are described; nuclear analytic methods and their application to benchmark experiments are discussed; and survey studies, a study of temperature and void coefficients, and a thermal-hydraulic analysis are presented. The contractor is Touro College. *EPRI Project Managers: B. R. Sehgal and A. G. Adamantiades*

Chemical Aspects of Denting in Steam Generators

NP-2177 Final Report (RP1167-3); $18.00

The chemistry and electrochemistry of reactions involved in steam generator tube denting due to localized corrosion of carbon steel under local acidic conditions were investigated. On the basis of the available literature, potential-pH diagrams were developed for the Fe-H_2O and Fe-Cl-H_2O systems and diagrams of stabilities of compounds were developed for the Fe-O-H system. The potential action of substances for inhibiting denting reactions as neutralizers, pore-blockers, and buffers was also studied. The contractor is Centre Belge d'Etude de la Corrosion. *EPRI Project Managers: Daniel Cubicciotti and Thomas Passell*

Development and Demonstration of an Advanced Methodology for LWR Dosimetry Applications

NP-2188 Interim Report (RP1399-1); $15.00

This report describes work (for use in a computer code) to develop an improved dosimetry methodology to reduce the uncertainty in flux and fluence estimates affecting LWR pressure vessels. It covers the theoretical basis of a least-squares adjustment procedure, various integral experiments and their calculations, the group structure and the parameters used in the analysis, the methods used for calculating data links and estimating covariances, and the results of applying the adjustment procedure to all input data. The contractor is Oak Ridge National Laboratory. *EPRI Project Manager: Odelli Ozer*

Reduction of PWR Moderator Temperature Coefficient by Gadolinium Substitution

NP-2191 Final Report (RP1453-1); $9.00

This report focuses on the specification of a core design concept for burnable poisons aimed at reducing the moderator temperature coefficient (MTC) of a PWR in the first portion of the first cycle. Results are presented on the addition of a relatively modest complement of axially zoned, gadolinia-loaded fuel rods in specific locations to produce a more negative MTC. The contractor is Science Applications, Inc. *EPRI Project Manager: W. J. Eich*

Critical Flow Data Review and Analysis

NP-2192 Final Report (RP1438-1); $22.50

This report presents an analysis of the Marviken large-scale critical flow test data. It compares the Marviken blowdowns with predictions by several existing two-phase critical flow models and summarizes parametric trends in the Marviken data. A survey of two-phase critical flow literature is included, as well as recommendations for modeling the critical flow. The contractor is S. Levy, Inc. *EPRI Project Manager: Avtar Singh*

Advanced Signal Processing of Turbine Rotor Bore Waveforms

NP-2203 Final Report (RP502-8); $12.00

This report describes the testing of five types of advanced signal-processing operations: temporal averaging, bandpass filtering, circumferential beamforming, reference subtraction, and spatial deconvolution. It details the data collection effort and presents features computed from the radio-frequency waveforms to establish Adaptive Learning Network (ALN) crack-inclusion discrimination, the ALN model structure, and coefficient results of the ALN crack-inclusion model. The contractor is Adaptronics, Inc. *EPRI Project Manager: Soung-Nan Liu*

BWR Transient Response: Blowdown/Emergency Core Cooling Test Phase, 1980 Activities

NP-2224-SR Special Report; $16.50

This report reviews the major accomplishments achieved during 1980 in system and separate-effects tests performed in the two-loop test apparatus simulating BWR 8 $\times$ 8 fuel bundle performance. Test results involving system simulation of large-break loss-of-coolant accidents and BWR behavior under small-break and low-flow bundle uncovery conditions are reported. *EPRI Project Manager: S. P. Kalra*

PLUNGE: A Computer Program for Transient Event Analysis

NP-2229 Interim Report (RP1233-1); $7.50

This report describes the computer program PLUNGE, an updated version of the SEARCH program that is used to perform various searches on a data base on transient events leading to reactor scrams. A program description is presented, including the four data sets used for input and an event flowchart. Input restrictions are discussed, output is described, and a sample problem is reviewed. The contractor is Science Applications, Inc. *EPRI Project Manager: D. H. Worledge*

ATWS, A Reappraisal: Part 3, Frequency of Anticipated Transients

NP-2230 Interim Report (RP1233-1); $24.00

This report presents an analysis of the frequency of shutdown occurrence data for 37 categories of BWR transients and 41 categories of PWR transients. The BWR data cover 903 events occurring over 101.5 plant-years at 16 different plants, and the PWR data cover 2093 events occurring over 213.4 plant-years at 36 plants. On the basis of these data, estimates of occurrence rates are calculated for all categories of transients. The contractor is Science Applications, Inc. *EPRI Project Manager: D. H. Worledge*

Technical Description and Evaluation of BWR Hybrid Power Shape Monitoring System

NP-2234 Final Report (RP1442); $18.00

This report discusses the method of monitoring BWR cores that has been implemented in the Power Shape Monitoring System (PSMS). A complete technical description of the hybrid PSMS and the results of detailed qualification testing are included. The contractors are Systems Control, Inc.; Nuclear Associates International, Inc.; and Hitachi, Ltd. *EPRI Project Manager: A. B. Long*

Stress Corrosion Characterization of Turbine Rotor Materials: Phase 1

NP-2237 Interim Report (RP1929-5); $12.00

This report describes research conducted to determine the susceptibility of steels used in low-pressure (LP) turbine rotors of power plants to stress corrosion cracking (SCC) in LP turbine environments. The research included slow-strain-rate and sustained-load SCC tests on samples from two 3.5 NiCrMoV rotor forgings. Tests were conducted in various environments over a temperature range of 38–204°C. The contractor is the Metal Properties Council, Inc. *EPRI Project Manager: A. J. Giannuzzi*

Evaluation of Safety Parameter Display Concepts

NP-2239 Final Report (RP891-5); Vol. 1, $16.50; Vol. 2, $19.50

This report reviews two experimental concepts for a safety parameter display system (SPDS) that were evaluated to assess benefits and potential problems associated with the SPDS concept and its integration into control room operations. Volume 1 presents background material, the evaluation results, and recommendations. Volume 2 contains appendixes of transient timelines and decision charts. The contractor is Westinghouse Electric Corp. *EPRI Project Managers: A. B. Long and John O'Brien*

Mechanistic Model for Predicting Two-Phase Void Fraction for Water in Vertical Tubes, Channels, and Rod Bundles

NP-2246-SR Special Report; $19.50

This report describes a mechanistic model for predicting two-phase vertical flow in heated rod arrays and other vertical geometries. Two separate modelings of the drift velocity are qualified by a comparison with experimental data. Appendixes cover development of the vapor generation form, choice of heat transfer coefficients, slip modeling, location of the point of net vapor generation, liquid-phase superheating, and comparisons with individual experiments. *EPRI Project Manager: G. S. Lellouche*

WHAMSE: A Program for Three-Dimensional Nonlinear Structural Dynamics

NP-2250 Computer Code Manual (RP1065-3); $12.00

This report describes the theory of the WHAMSE computer code—a three-dimensional, explicit, finite element code for the nonlinear transient analysis of structures—and presents a user's manual. Included are WHAMSE nomenclature and notation; equations of motion; descriptions of the beam, plate, and spring elements; details on program input and features; and sample problems. The contractor is Northwestern University. *EPRI Project Manager: R. N. Oehlberg*

B&W FREY Calculations: Four-Pump Coastdown, Locked Rotor, Rod Group Withdrawal

NP-2252 Final Report (RP1627-2); $7.50

The FREY (fuel rod evaluation system) code is evaluated for three operational transients: four-pump coastdown, locked rotor, and rod group withdrawal. FREY predictions are compared with those of the Babcock & Wilcox LYNXT code. Code inputs and outputs are described. The contractor is Babcock & Wilcox Co. *EPRI Project Manager: R. N. Oehlberg*

PLANNING AND EVALUATION

1982–1986 Research and Development Program Plan

P-2155-SR Special Report; $33.00

This report presents detailed descriptions of EPRI's 39 R&D programs for the period 1982–1986. Each program description contains a logic diagram, an explanation of the program's importance to the electric utility industry, an outline of the work to be done, and an identification of motivating issues and technical impediments. Key-event charts that show the planned accomplishments and anticipated rate of progress for the programs are also included. *EPRI Project Manager: James Arcella*

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