Cooling Commercial Buildings

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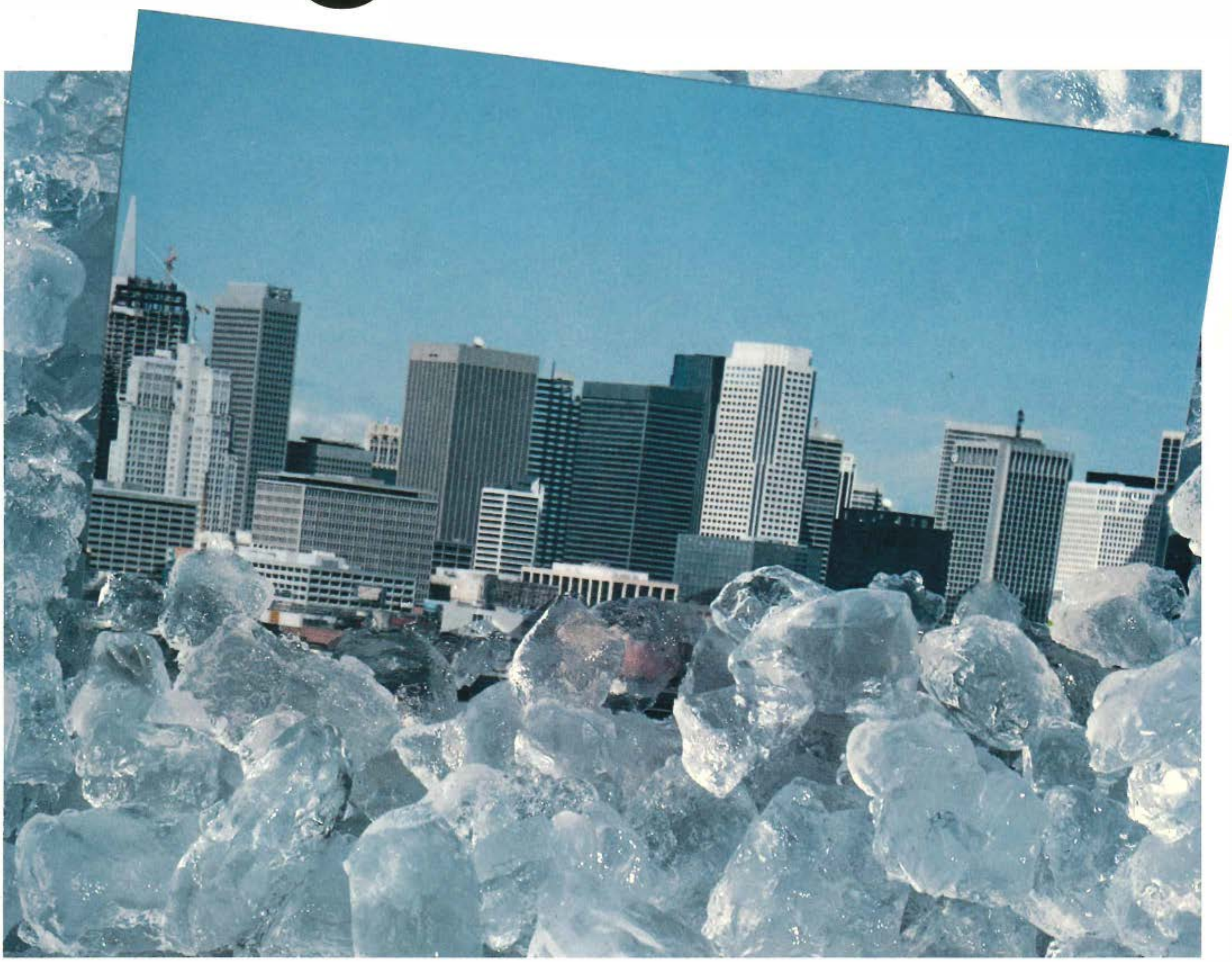

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Cover: Water chilled or frozen with off-peak power is being used for comfort conditioning in large commercial buildings.

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Cool Storage in the Commercial Sector

In the public's eye, energy research is seen in terms of the solar collector on the roof of the private residence or the high-tech energy-efficient demonstration home getting a play in the news media. Indeed most—although admittedly not all—of the emphasis of utility programs and federally funded building research has been on the residential homeowner or apartment dweller. But the opportunites in the commercial sector for improving energy efficiency and reducing costs to utilities and their customers are just as challenging and, as the utilities are learning, in some cases more realizable.

About a third of the summertime peak demand of many utilities is attributable to air conditioning commercial buildings, even though these buildings constitute only a relatively small fraction of a utility's customers. Moreover, almost half of the air conditioning demand imposed by commercial customers typically comes from less than 4% of the buildings—the large offices, department stores, institutional buildings, and so on. The relatively high electricity prices these customers pay reflect the utility's costs of maintaining and operating plants to meet the peak loads contributed by these buildings.

This month's lead article on cool storage in commercial buildings illustrates one approach to reducing commercial customers' costs through innovative technologies. Instead of operating the air conditioning system continuously when the cooling is needed during the business day, the system can be run at night, when lower electric rates are available, and the "cool" stored in chilled water or ice; some or all of the next day's cooling requirements can then be supplied from storage. Reducing or entirely eliminating on-peak system operation flattens the building's electric load, reducing peak demands and electricity costs. Meanwhile, on the utility system, the power plants can be operated more efficiently to produce electricity at a lower cost to the customers.

But having the basic concept and hardware at hand is only the first step in accelerating the acceptance of thermal storage as a building comfort-conditioning option. Uncertainties about the factors that affect the system's operation and its reliability frequently result in overdesign, operating problems, and increases in costs. These costs can be reduced and performance improved through further research. For example, better separation of the chilled and the warmer water in the tank can increase the effective storage volume, and improved ice and refrigeration subsystem design can reduce the system's energy consumption. Design and performance prediction methods have to be developed and validated against actual experience. Finally, design procedures, guidelines, and information on experience with operating systems have to be communicated in easily understandable and readily usable form to utilities' commercial services staffs, the architectural and engineering community, building owners and developers, code officials, and others.

EPRI's commercial-sector research programs are growing. In addition to improved design and engineering of thermal energy storage systems, research is also proceeding on the development of better algorithms and components for building energy management systems, better lighting controls and application methods, and improved refrigeration systems. Implementation of cool storage in commercial buildings should be a milestone for the growing cooperation between utilities and their customers, as its economic and load management aspects work to the benefit of all parties involved.

Arvo Lannus
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Authors and Articles

Rabl

Feher

Electricity to run air conditioning systems is such a big fraction of demand today that the peak-generating season for some utilities has shifted from winter to summer. **Cooling Commercial Buildings With Off-Peak Power** (page 6) explores the pivotal role of large commercial buildings and the renewed R&D of ways for them to store "cool." The author is Nadine Lihach, senior feature writer for the *Journal,* drawing on investigations managed by EPRI's Veronika Rabl.

Rabl came to the Energy Conservation and Utilization Technology Department in October 1981, after having managed technical and economic analyses for DOE. Earlier, from 1975 to 1980, she was at Argonne National Laboratory, becoming an assistant engineer in the Energy and Environmental Systems Division. Rabl studied at the Czech Technical University of Prague but earned her MS in physics at Weizmann Institute of Science in Israel. She also has a PhD from Ohio State University.

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Numbers define the near-term trends used in R&D program planning. But for looking 20 years or more ahead, it is necessary to consider the issues and opportunities that are likely to influence the numbers. **Plans and Perspectives: The Industry's View** (page 14) describes a part of EPRI's strategic planning that identifies and weighs those issues. Taylor Moore, *Journal* feature writer, is the author. Frank Young and Sherman Feher provided background from their work in EPRI's Planning and Evaluation Division.

Young has been with the Institute since September 1975, at that time in transmission line research but since 1977 in strategic planning, which he has managed for the last 2 years. Young was previously with Westinghouse Electric Corp. for 20 years, eventually becoming manager of UHV transmission research, in which capacity he was briefly on loan to EPRI. Young holds BS and MS degrees in electrical engineering from Stanford University and the University of Pittsburgh, respectively.

Sherman Feher, an EPRI planning ana-

Dunlap

Young

lyst since August 1978, works with siting and environmental issues that influence utility industry R&D planning, especially in connection with solar, wind, and geothermal energy systems. He was previously an urban planner, associated successively with the county of Santa Clara and the city of San Jose, California. Feher graduated in geography from California State University at Hayward and earned a master's degree in urban planning at California State University at San Jose.

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Sharing right-of-way easements makes excellent sense and saves money for electric utilities, railroads, and pipeline companies. But overhead transmission lines mean electromagnetic fields and the possibility of induced voltages in other facilities. **Induced Voltage in a Shared Corridor** (page 20) is an update on cooperative research that is now producing rigorous analytic solutions where problems arise. Science writer Rosalyn Barry wrote the article, based on discussions with John Dunlap, project manager in the Overhead Transmission Lines Program of EPRI's Electrical Systems Division.

Dunlap came to EPRI in February 1979. Previously, he was supervisor of the Existing Transmission Lines group at Florida Power & Light Co., where he had worked for 21 years. Much of his responsibility there was for redesigning and converting transmission lines to higher voltage. Dunlap is an electrical engineering graduate of the University of Tennessee.

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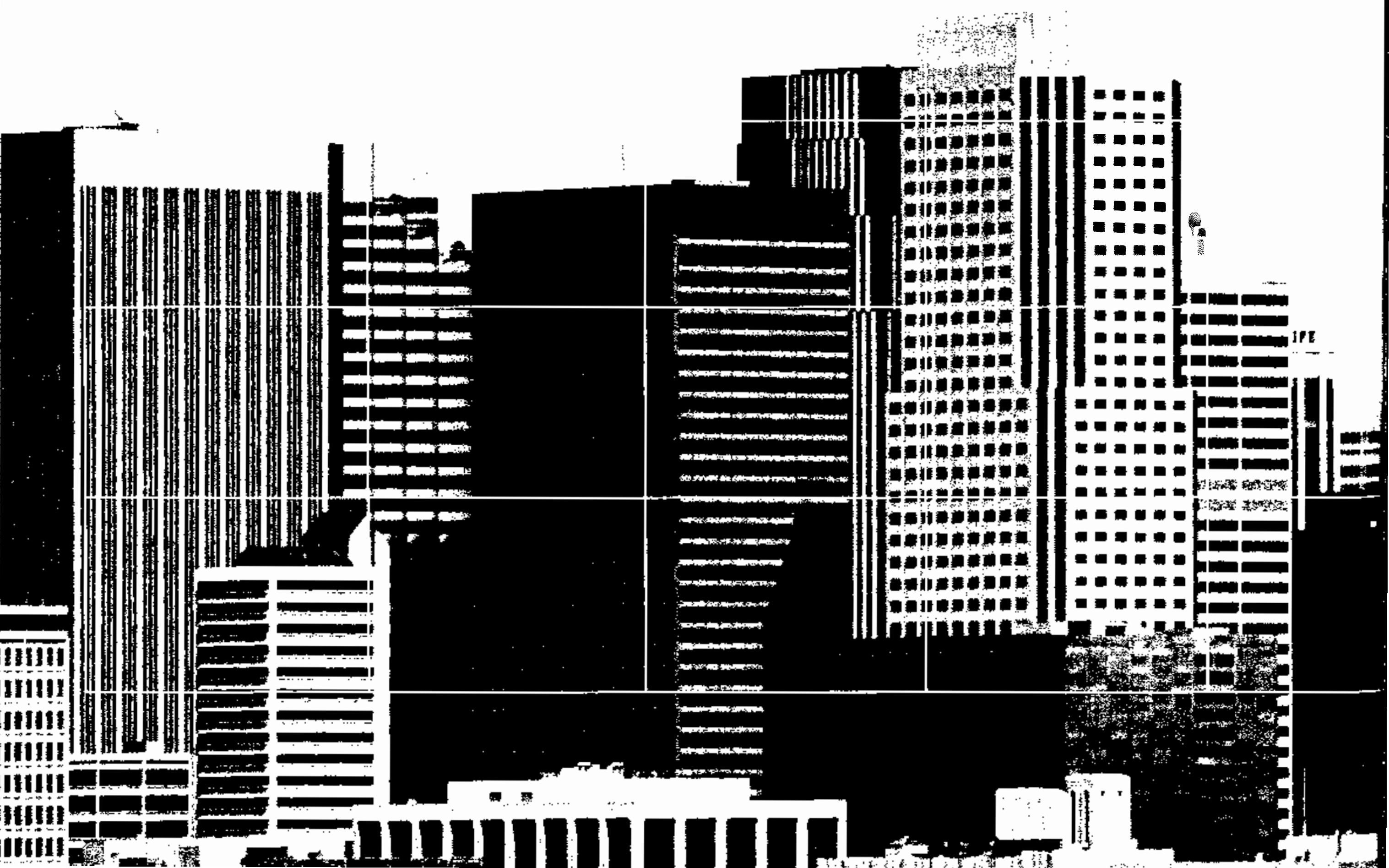
Economic regulation has been a special field for Paul Joskow during most of his 11 years on the economics faculty at Massachusetts Institute of Technology. Energy policy—especially as related to electricity and utilities—occupies much of his time as a professor, author, and (since 1980) member of EPRI's Advisory Council. **Paul Joskow: Accent on Economic Efficiency** (page 23) is a profile drawn by Marie Newman, now a freelance writer but formerly on EPRI's Washington, D.C., staff.

COOLING COMMERCIAL BUILDINGS WITH OFF-PEAK POWER

Commercial cooling requirements can account for as much as 40% of a utility's peak demand on a hot summer day. Cool storage can shift some or all of this peak period cooling demand to off-peak periods.



Mech.

Cooling, not heating, is the main concern of the owners of large commercial buildings. These buildings—populated by hundreds of people, illuminated by thousands of lights, and humming with typewriters, photocopiers, computers, and other business equipment—generate so much heat that cooling is required not only on the hottest days of the year but virtually all year round. The hours when commercial cooling is needed fall during peak electricity demand periods, which means building owners must pay significantly higher rates to cool their buildings with air conditioners run on peak-priced electricity.

Meeting requirements

The cooling of large commercial buildings is a major concern for the electric utility industry, too. Since the advent of widespread central air conditioning in the 1960s, the cooling of commercial buildings has escalated to a hefty share of the industry's summer peak in many parts of the country; air conditioning has even transformed many former winter-peaking utilities into summer-peaking utilities. To meet these large peak period cooling requirements, utilities have to keep extra generating capacity on line, usually gas- or oil-fired peaking units. Not only is the capital investment in these plants large but the cost of operating them is high. And because these plants are only needed for a few hours of the day, the investment is even more disadvantageous for the utility. The consequence: higher peak period electricity costs.

Happily for both utilities and building owners, there is a way around this high peak demand and correspondingly high peak electricity costs. Some or all of the peak period cooling demand of large commercial buildings can be shifted to off-peak periods by using a technique called cool storage. The concept is simple. Instead of operating the compressor of the building's air conditioning system during peak periods, the equipment is

B&W print

switched on during off-peak periods. The compressor does not cool the building directly; instead, it chills water or makes ice, and the water or ice is stored in large steel, concrete, or fiberglass tanks (usually located in the basement or mechanical room of the building, or sometimes outside the building) until hours later when cooling is needed. Then, the chilled water—or water that has been circulated around the ice—is pumped through the building's cooling coils. Air is forced over the coils for comfort cooling and dehumidification.

Cool storage is being used right now: about 100 commercial buildings of all sizes in the United States and Canada have systems in operation: more are under construction. Cool storage systems are also in service overseas—in Japan, for example. Only a few of these installations were built for experimental purposes; most were installed because their owners felt they would produce a marked reduction in the building's cooling bills.

Many of the cool storage systems are living up to expectations, indicates a recent report from Inform, Inc. A manufacturing and laboratory facility in Tucson, Arizona, with 2.5 million gallons (9460 m^3) of storage capacity (26,800 ton-hours, one ton-hour equaling 12,000 Btu) cost its owners $500,000 and is saving them $140,000 a year in electric bills; this system should pay for itself in three or four years. A manufacturing, laboratory, and administrative building in Charlotte, North Carolina, with 500,000 gallons (1890 m^3) of storage capacity (3200 ton-hours) is estimated to save $46,000 a year. A data processing, education, and administrative building in Toronto with 945,000 gallons (3580 m^3) of storage will save an estimated $75,000 a year and pay for itself in about four years.

In addition to savings in electric bills, cool storage systems can be installed—under the right circumstances—at prices comparable to those of conventional air conditioning. In San Francisco, for example, a 2000-ton-hour system installed in a new building actually cost no more than a conventional air conditioning system and is expected to save about $38,000 annually in electric bills.

Despite these successes, most new buildings continue to employ conventional air conditioning and to incur high bills for peak period electricity. Building owners and consulting engineers settle for ordinary air conditioning systems because cool storage, with its bulky tanks, refrigeration systems, and off-beat operating hours, is still an uncommon concept. And although many cool storage systems are now in operation, there is surprisingly little available information on their design, performance, economics, operation, and maintenance. The few engineering firms that design cool storage systems have generally worked on their own, coming up with in-house designs and economic analyses. Few of the resultant installations have been instrumented and monitored for performance. For building owners and their engineers to be willing to take a chance on cool storage, more information on this novel technology is necessary, and that information is being provided through a brand-new series of EPRI projects that includes a design manual, a brochure on how to estimate electric bill savings, and engineering studies.

Old-time cooling

Cool storage may be an uncommon technology, but it is certainly not a new technology. It had its unsophisticated beginnings in the early decades of this century when ice cut from frozen ponds and lakes was delivered to the basements of large buildings, such as banks, hotels, and department stores. As the ice melted in its holding bins, the chilled water was pumped to chambers known to the fledgling cooling trade as air washers. Inside these air washers, the chilled water was forced through spray nozzles as the ambient air was forced through the washer. The water cooled the air, and the air was circulated throughout the building.

Air washers were used for building cooling from about 1910 through the 1930s and are still in use in a few places. But by the mid 1930s, air conditioning as it is known today had arrived in the form of small, packaged units. These small units followed essentially the same working principles as today's large centralized systems. They used electricity to run a compressor; the compressor compressed a refrigerant; the refrigerant circulated through evaporator coils, and as the refrigerant expanded within the coils, it absorbed heat. A fan forced ambient air over the coils, cooling the air in the process.

The public was enthralled by this new method of cooling buildings, and after a brief pause during the lean years of World War II, air conditioning rallied, stronger than ever, in the late 1940s and early 1950s. The systems were steadily improved upon, becoming more and more efficient, while at the same time electricity prices obligingly plummeted. The popularity of air conditioning was ensured, and by the 1960s it was well on its way to becoming a ubiquitous technology.

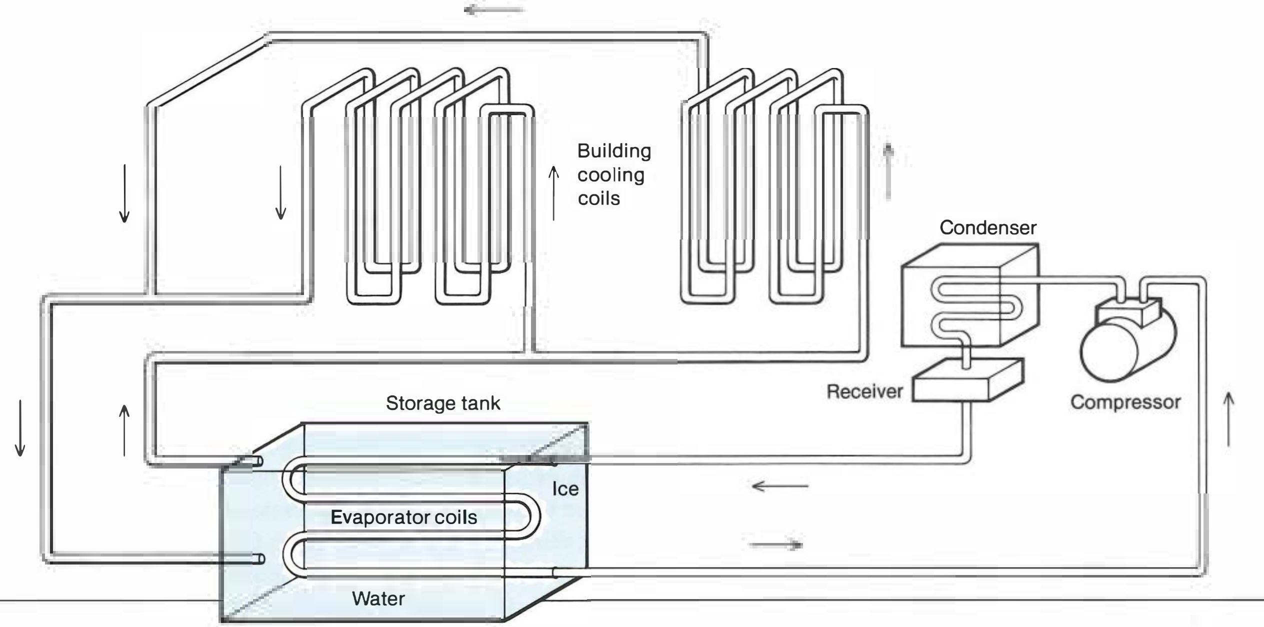
Yet as air conditioning was developing, it became apparent that the system was not practical for all customers. Churches and auditoriums, for example, needed cooling for only a few hours a week, but their loads were so large that sizable—and costly—air conditioning systems were required to deal with them. The owners of these buildings could not justify purchasing large air conditioning systems to meet the infrequent loads, and in many cases limited electric wiring would not permit a large air conditioning load. Nevertheless, these buildings still needed cooling, and the solution was cool storage, in the guise of so-called ice banks.

The ice bank worked as follows: A small compressor in a church chugged along all through the week, producing ice that was stockpiled in bins at the back of the building. At the end of the week, when it was time for services and Sunday

Ice Storage

Mech

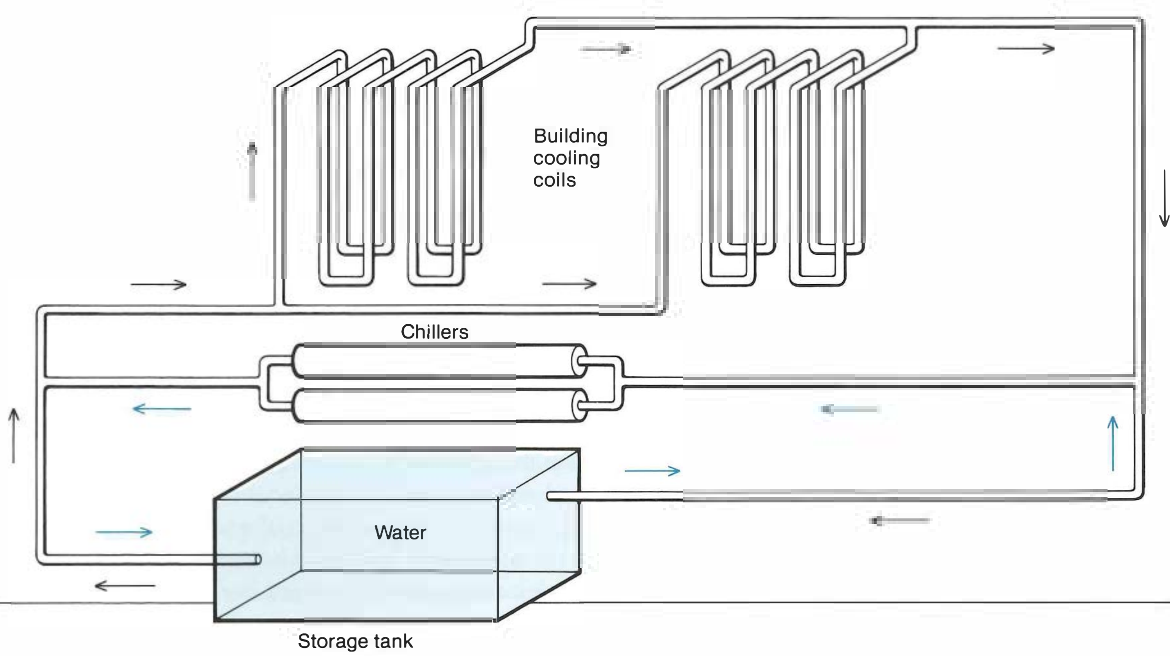
During off-peak periods, compressors compress a refrigerant that is circulated through evaporator coils submerged in a tank of water. As the refrigerant expands, it absorbs heat, and a sheath of ice builds up around the coils (some ice systems spray water on the evaporator coils and harvest thin layers of ice instead). When cooling is required, the cold water in the tank is circulated through the building's cooling coils.



Chilled-Water Storage

Mech.

During off-peak periods, water is chilled by the chiller's compressors and pumped to the storage tank. When peak period cooling is required, the chilled water is pumped through the building's cooling coils or through a heat exchanger that cools the water in those coils.



school, a fan blew air directly over the ice bins or chilled water from the bins was pumped through a coil, and the congregation was effectively cooled. The capital cost for an ice bank system was agreeably modest, and because of their economy and efficiency, ice banks were used through the 1940s and 1950s until the price of large air conditioning systems came down to more affordable levels.

Cool storage systems were revived in the late 1970s and early 1980s but on a grander scale and for different reasons. This time around it was not the small, occasional customers who needed cool storage to avoid high capital costs; it was large commercial customers—buildings with floorspace greater than 50,000 ft^2 (4650 m^2), which account for nearly half of the commercial sector's floorspace—who needed relief from high peak period electricity prices.

Today's large commercial buildings, usually multistoried offices, need cooling daily, not for just a few hours on Sunday. They also need cooling year-round, not only in summer but in winter as well. Recent statistics indicate that the space cooling of commercial buildings (large and small combined) makes up 25–40% of the utility industry's summer peaks, compared with only about 5–20% for residential space cooling. By contrast, winter space heating of commercial buildings accounts for a scant 1–10% of the winter peak versus residential's 20–40%. Plainly, commercial buildings need significant amounts of cooling during peak periods, especially summer.

The prices that owners of large commercial buildings have to pay for peak period cooling are also significant. Utilities base customer rates on two basic components: energy and demand. Energy charges, which reflect operation and maintenance costs, may vary throughout the day. A typical range for energy is 2–5¢/kWh for off-peak periods, creeping up to 4–10¢/kWh for peak periods.

Demand charges reflect how much the utility has to spend to ensure that power is available to the customer whenever needed. Demand charges for peak period electricity both compensate the utility for having peaking equipment sit idle most of the time and encourage customers to avoid peak period use. Typical demand charges may be $0/kW per month during off-peak periods but escalate to $4–$5/kW per month during peaks. Some demand charges may be as high as $15/kW, or higher, per month. If a building incurs most of its electric load during peak hours, the bills will be sizable.

As an illustration of the dollar savings that a cool storage system can achieve, Veronika Rabl, manager of cool storage research projects in EPRI's Energy Management and Utilization Division, offers this example: Conventional air conditioning of a hypothetical 100,000-ft^2 (9290-m^2) office building contributes almost 200 kW to its peak demand. A demand reduction of more than 100 kW could be achieved by installing about 1000 ton-hours of storage (100,000 gallons [380 m^3] of chilled-water storage, or about 90,000 lb [40.8 Mg] of ice storage). The storage system would cost about $20,000–$40,000, or $200–$400 /kW of reduced demand. The resulting annual bill savings would amount to about $70–$90/kW, or $7000–$9000. The storage system would also shift about 1000 kWh a day to off-peak periods, and the owner could benefit further from any available off-peak rates.

Why there's hesitation

Despite the combined incentives of high peak demand and bill savings, consulting engineers hesitate to incorporate cool storage into new buildings or to retrofit older structures. Consider the engineer's point of view—his job is to design for his client a system that is both cost-effective and reliable. "But consulting engineers are generally unfamiliar with cool storage systems, so they feel that there is a certain amount of risk involved in trying them," explains Rabl.

The risks are real. Cool storage systems have developed tank leaks, control problems, and rust. Engineers are naturally concerned that if the cool storage system malfunctions for any reason, the building's owner may have to pay unwelcome repair bills, while losing the savings that the system is supposed to guarantee. Even worse, if the building's air conditioning system has been downsized because of confidence in the cool storage system, the building might be left without adequate cooling capacity at a critical moment.

"Engineers as a group are not all that anxious to incur gambles and higher engineering costs," comments Robert Tamblyn, principal of Engineering Interface, Ltd., an Ontario firm that designs cool storage systems. "On one hand, they have to move ahead with new designs. On the other, they don't like making mistakes. There are enough complications in buildings without getting off the beaten track." Thomas Gilbertson, of Thomas Gilbertson and Associates, a firm in Moraga, California, that also designs cool storage systems, agrees. "There's little financial incentive for the engineer to do more than the absolute norm. If he does, he may have to do more work, spend more money, take more risks, and he may not get any help." Small wonder, then, that few consulting engineers have abandoned the tried-and-true system of air conditioning. Their clients usually are not too concerned with which system the engineer chooses as long as it is cost-effective and reliable. Unless the engineer's client is bent on a cool storage system and is willing to take the risks, traditional air conditioning is the routine choice.

Although consulting engineers prefer to stick with conventional air conditioning, cool storage systems are not excessively complicated. Most of the ice systems installed today are static systems. During off-peak periods, compressors compress a refrigerant and the refrigerant is circulated through evaporator coils; as the refrigerant expands in the coils, it absorbs heat. The coils, which are submerged in a tank of water, build up a sheath of ice, enough to meet some or all of the next day's peak period cooling load. During peak hours, the cold water remaining in the tank is circulated throughout the building for cooling.

Dynamic ice systems work a little differently. Water is sprayed onto evaporator coils, and the resultant thin layers of ice are periodically harvested into bins. Water circulated through the bins provides the cooling medium for the building. Chilled-water systems also use compressors, but to chill water, not to make ice. The water is stored in large tanks, and when the peak hours arrive, the chilled water is either circulated directly throughout the building or past heat exchangers, which transfer the coolness to the building's cooling system.

Both ice and chilled-water systems have advantages and disadvantages, explains Rabl. Because ice delivers so many more cooling Btu per pound than chilled water, ice systems are usually two to five times smaller than chilled-water systems, even taking into account the liquid water that the ice system needs for adequate circulation and heat exchange. This makes the ice system a more likely choice for retrofit installations in existing buildings, where tank space in basements or machine rooms is apt to be limited. Because of their smaller size, ice systems are also available in package form, rather than having to be entirely custom-designed, as are chilled-water systems. Another advantage that ice systems might have over chilled-water systems is that they deliver colder water to the building, which may permit smaller circulating pumps, heat exchangers, and air handlers, and therefore they may reduce energy consumption.

On the debit side, ice systems require lower evaporator temperatures to produce ice, so system efficiency is lower than that of chilled-water systems, and a somewhat larger—and more costly—refrigeration system is required for ice.

Chilled-water systems lack the ice-making step, so they are also a little easier to control than ice systems. But they do require more storage space, are usually custom-designed, and are therefore better suited for new buildings than for retrofits because engineers can allow room for them in their designs. Chilled-water tanks may also be used to store hot water during the heating season, if necessary.

Shortage of information

Most engineers would agree that the basics of cool storage are simple. But beyond the basics, things can get tricky for consulting engineers accustomed to dealing with conventional air conditioning packages. The engineer has to consider whether cool storage can pay its own way through savings in electric bills and whether the building has space for the system. He has to determine system sizing, decide on system controls, and consider system operation and maintenance. This is where engineers can use some assistance. Not only is there little available information on cool storage systems, according to Rabl, but the decisions vary from building to building, situation to situation.

Consider cost-effectiveness, one of the most important criteria for cool storage. It is fairly plain that a night club or theater that requires cooling in the evening hours has little to gain from cool storage and that a nine-to-five office, school, or similar commercial or light industrial building with a brief, sharp peak for a few hours at midday is a good cool storage prospect. But it requires careful study of the local utility's rate schedule to determine if the system can pay for itself in a reasonable period of 3–5 years. Most utilities charge for demand, but the rates vary from service area to service area. Many utilities also ratchet their rates, which means they bill customers according to the highest demand incurred during a period of anywhere from about six months to a year. Thus, a customer able to reduce his summer peaks by cool storage stands to benefit by lower demand rates the rest of the year. Rate schedules that offer lower rates for off-peak use are another cool storage incentive. Whatever the situation, the engineer has to investigate the rate schedule thoroughly.

Another area where engineers could do with some guidance is system sizing. There are two general approaches: full and partial storage systems. Full storage meets the entire peak period demand. Partial storage meets part of the demand by storage and the rest by conventional air conditioning. The advantage of full storage is that the building owner collects the largest possible benefits from off-peak rates. Full storage, however, requires the largest capital equipment investment: a full-sized refrigeration system and a full-sized storage system.

Partial storage requires less refrigeration equipment and less storage space because the refrigeration equipment operates continually. Partial storage has its drawbacks, however. Because its refrigeration equipment runs day as well as night, it does not achieve the same amount of demand reduction as the full-storage mode. Further, if the storage portion of the system fails, the downsized refrigeration system may not be capable of cooling the building by itself during peak periods. Even when the engineer has made his choice between full and partial storage, he has to figure out the fine details of exact system sizing, such as storage tank volume and refrigeration equipment capacity.

Still another uncertain area is cool storage operation and maintenance. "Operation and maintenance of cool storage systems is not necessarily more difficult that that of conventional air conditioning systems," says Rabl. "There is, however, more equipment to take care of, and the operating procedures are different." Controls are of particular concern. For example, if the system's time clocks miss and permit the compressor to run over into a peak period, electricity rates may be raised for months to come. More and more cool storage systems include computer controls in the effort to keep a tighter rein on the system.

Sizes and configurations of cool storage systems vary, depending on the type of cool storage (chilled water or ice) and the design of the individual system. The newly installed ice storage system at Equitec Properties Co.'s Los Angeles World Trade Center consists of eight cylindrical ice storage tanks, each 3 ft (0.9 m) in diameter and 44 ft (13 m) in length, which store up to 126,000 lbs (57 t) of ice. The tanks are housed in a vault adjacent to the building, below ground level. This 2000-ton-hour cool storage system supplements an existing air conditioning system to cool a total of 420,000 ft² (39,000 m²) of space.

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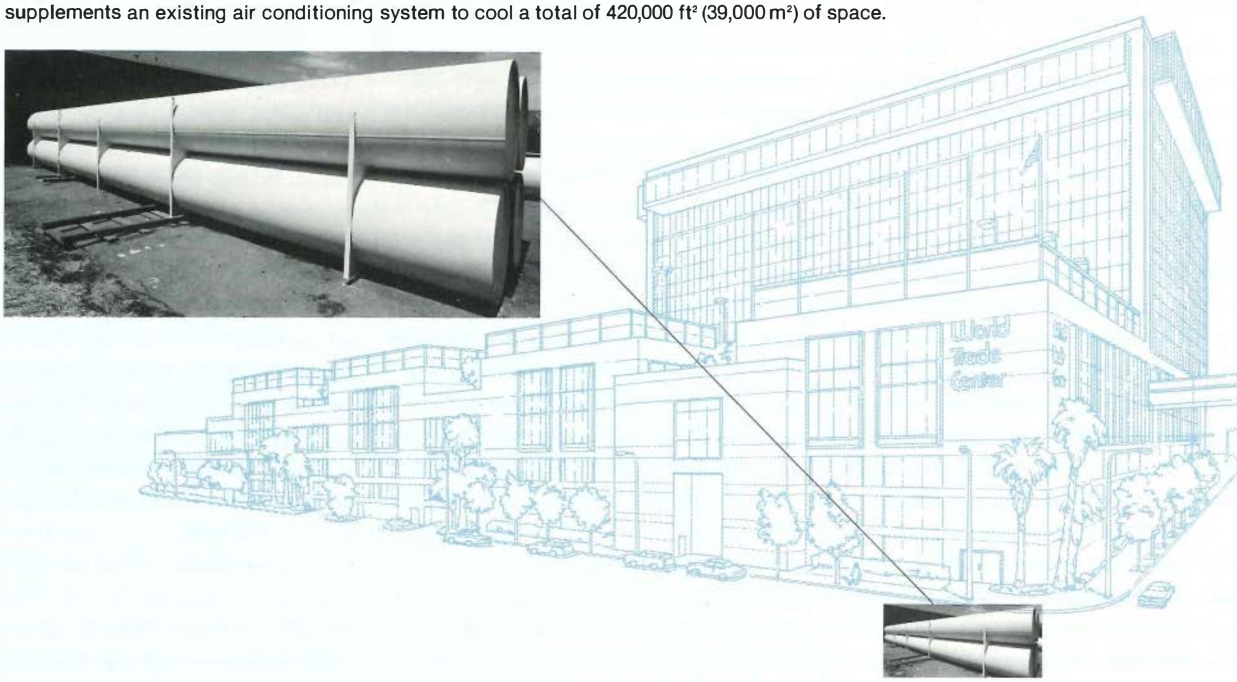

The ice storage system at Union Oil Co. of California's Fred L. Hartley Research Center in Brea, California, has a capacity of 13,200 ton-hours. Two 40 by 60 by 11 ft (12 by 18 by 3 m) outdoor steel storage tanks produce 1,100,000 t of ice to air condition 280,000 ft² (26,000 m²) of building space during the day (a conventional air conditioning system takes over at night). Three circulating water pumps deliver the chilled water to the many buildings in the complex.

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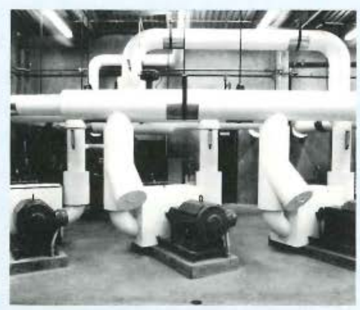
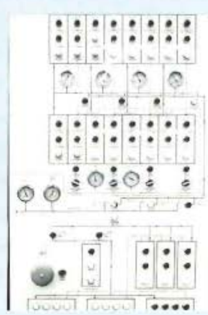
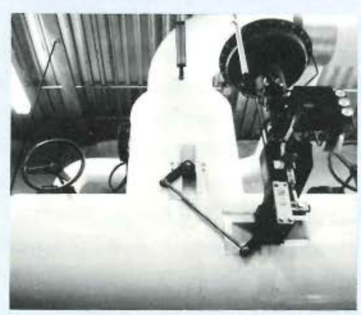






Answers for engineers

Ready answers for questions about such subjects as cost-effectiveness, system sizing, and control would go a long way toward stimulating the installation of more cool storage systems. Because cool storage may smooth the system load profiles of many utilities and possibly may help them postpone or even eliminate construction of new power plants and transmission and distribution systems, several utilities with high load growth rates are already attempting to spread the word about cool storage to consulting engineers through seminars, brochures, and an occasional guidebook. Some utilities are trying to promote cool storage installations by offering special rebates for kilowatts or kilowatthours shifted to off-peak periods; at least one is offering to help fund cool storage feasibility studies.

EPRI has received dozens of requests for assistance from utilities that want to encourage engineers to use cool storage but lack the necessary selection guidelines and cost and performance information to promote it. To respond to these immediate needs, EPRI cosponsored two cool storage seminars, one with Potomac Electric Power Co. and one with General Public Utilities Corp. In a joint effort with GPU, EPRI is now developing a commercial cool storage design manual for engineers. The manual, due out by the end of the year, will substantially expand and update a guide developed three years ago by Southern California Edison Co. The new manual will cover economic considerations, system concepts, design and sizing, and operating strategies. Besides putting together the manual, EPRI is also developing a packaged seminar presentation that utilities can follow to present information on cool storage to consulting engineers in their service areas.

A complementary EPRI effort—development of a methodology for estimating electricity savings with cool storage systems—has been completed recently and should take some of the mystery out of rate schedules. The methodology is now available in a brochure and will also be incorporated into the manual.

The Energy Management and Utilization Division's Residential and Commercial Program has also been initiating projects in support of a longer-term research agenda. The ultimate goal of EPRI's cool storage research is to develop the technology and methods that will permit a designer to fully integrate the cool storage system with the building HVAC system to ensure the best match for a given application. This requires fundamental improvements in understanding the fluid mixing and heat transfer factors that influence cool storage efficiency, as well as the development and validation of models for the comparison and selection of alternative cool storage system designs, for the evaluation of control algorithms, and for the prediction of system performance.

As part of this longer-term effort, EPRI is evaluating the field performance of cool storage installations now operating in five commercial buildings. Field performance of cool storage systems is usually not monitored by building owners, but through the help of utility members, EPRI discovered five systems that had not only been instrumented by their owners or by utilities but had also been monitored for at least one cooling season. EPRI will collate data from the five sites to assess their performance and operating experience and to test and validate ice storage engineering models being developed in parallel. Actual performance at each installation will be compared with design expectations. Results will be available in the spring of 1984.

EPRI has also begun to investigate techniques for thermally stratifying chilled-water tanks. Thermal stratification, or the separation of a tank into areas of cool and warm water, has great potential for reducing the capital costs of chilled-water installations. Instead of building a minimum of two tanks—one for cool water, the other for water returning to be chilled—an engineer need build only one stratified tank.

But heat transfer and mixing tend to reduce the effectiveness of a stratified storage system, thereby increasing the size and cost of the tank. EPRI's research is aimed at maximizing the efficiency of stratified storage systems. Accordingly, EPRI is collecting full-scale experimental performance data on three different stratification systems: a flexible membrane that moves up and down inside the tank as water levels change; arrays of nozzles at the top and bottom of the tank that add or withdraw water of one temperature so evenly and gently that layers of another temperature remain undisturbed; and linear diffusers, which follow a similar principle. Small-scale acrylic plastic models are also being used to collect data and predict the performance of full-scale tanks. Results are due next spring.

Promising option

These projects will not answer every cool storage question, but they are a good start in the right direction. As reliable designs and data become more readily available, engineers will gain more confidence in cool storage systems, and more such systems will likely be built. By reducing their peak period electricity demand, the owners of well-designed cool storage systems will immediately enjoy reduced electric bills. As for utilities, cool storage is an important option for improving load factors and thereby lowering the cost of service. ■

Further reading

Thermal Energy Storage: Cooling Commercial Buildings by Using Off-Peak Energy. Seminar proceedings, RP2036-2, sponsored by Potomac Electric Power Co., U.S. Dept. of Energy, and EPRI, February 1982. EPRI EM-2244.

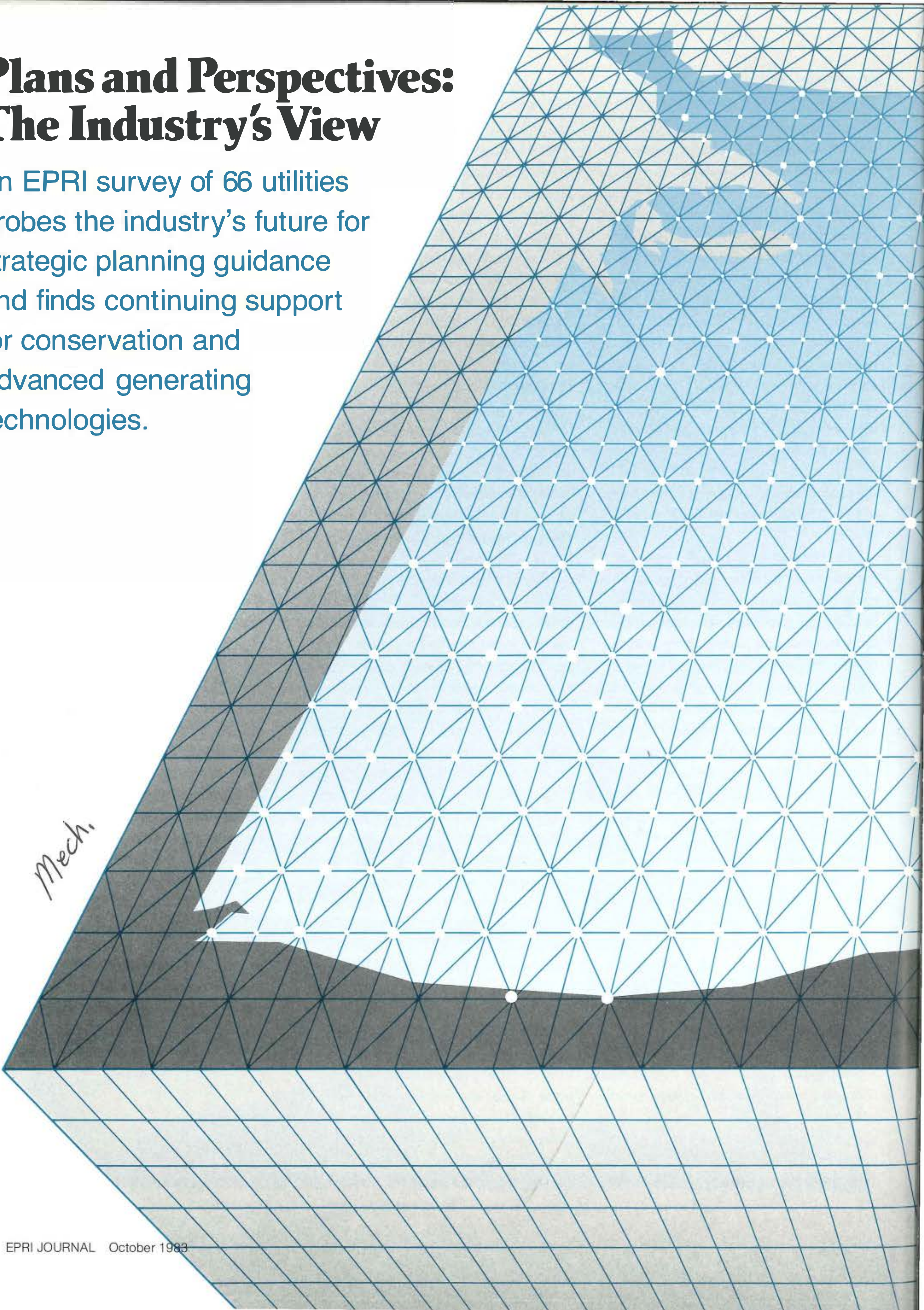
Pollack, Kenneth. *Energy Storage, Four Major Alternatives: Heat Storage, Cool Storage, Compressed Air Energy Storage, and Underground Pumped Hydro Storage.* New York: Inform, Inc., 1983.

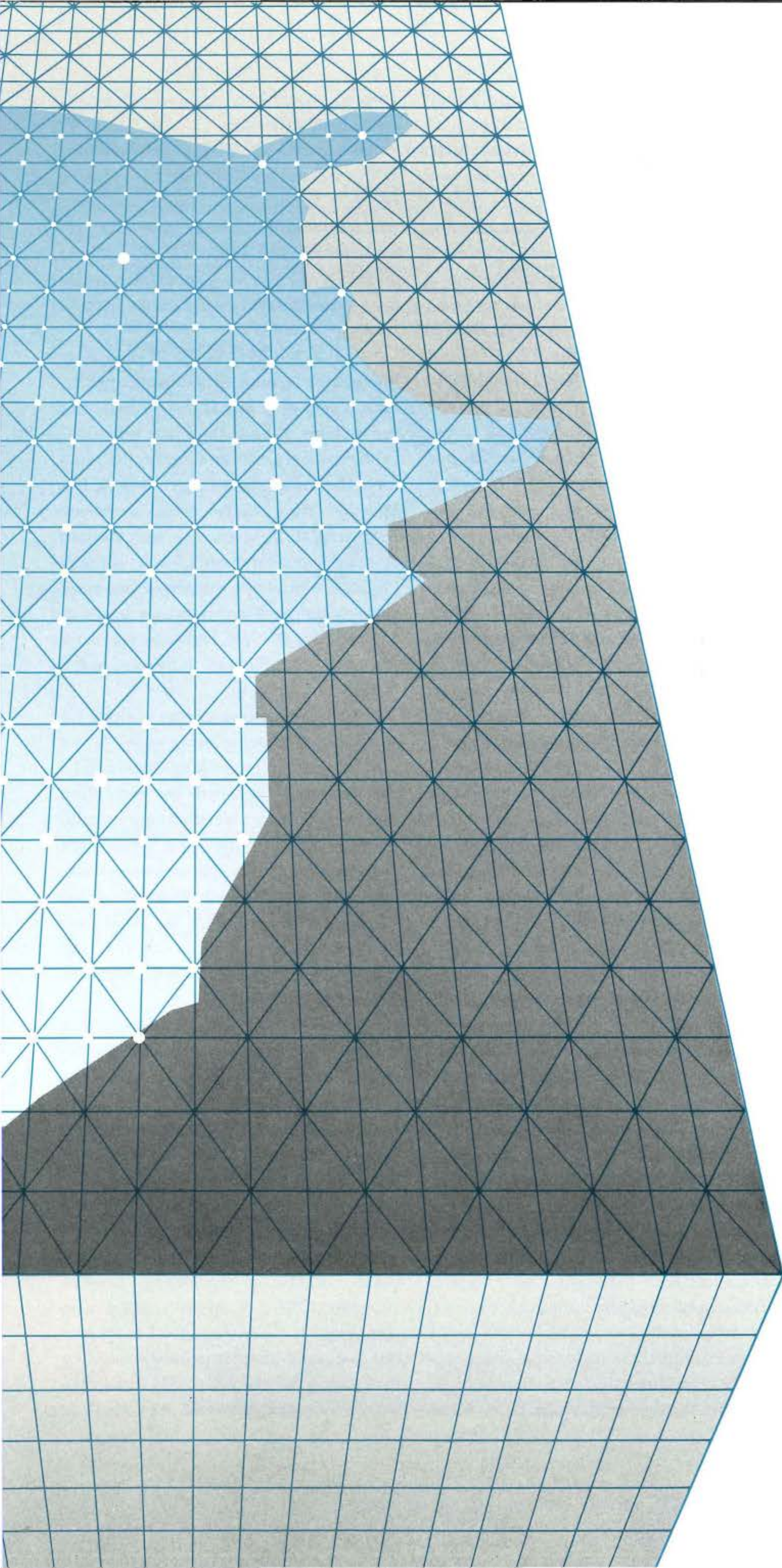
Opportunities in Thermal Storage R&D. Special report prepared by EPRI, July 1983. EPRI EM-3159-SR.

This article was written by Nadine Lihach. Technical background information was provided by Veronika Rabl, Energy Management and Utilization Division.

Plans and Perspectives: The Industry's View

An EPRI survey of 66 utilities probes the industry's future for strategic planning guidance and finds continuing support for conservation and advanced generating technologies.





What kind of future do the nation's electric utilities see for themselves over the next 20 years? What will be the principal challenges for them in the coming two decades? And how well does EPRI's R&D program fit this envisioned future?

These are tough questions to ask of any industry, let alone one vulnerable to unpredictable and, to a great extent, uncontrollable changes in socioeconomic, environmental, and political factors. But answers to them are crucial if the industry's research and development arm is to provide its sponsors with the tools needed to meet future challenges.

To obtain such answers requires asking thought-provoking questions of many different utilities. The patterns of response that emerge begin to take form as an industry's response—more than just the sum of individual answers.

Such is the rationale of EPRI's periodic Industry Advisory Committee Survey, an extensive probing designed to elicit the collective thinking of member utilities who are represented on EPRI's advisory committee. The results comprise a unique blend of perception, judgment, and expectation. The product of such an effort becomes a key input in EPRI's strategic planning process as part of a feedback loop that allows the Institute to synchronize its R&D priorities with the changing needs of its members.

"We use it to strengthen our view of the future, as well as to supplement our own analysis," explains F. S. Young, manager of strategic planning at EPRI. Richard Zeren, director of the Planning and Evaluation Division, likens the survey process to "trying to paint a picture of the industry. We get some interesting insights into the industry—how it's changing, how it's coping with its current difficulties, and how it hopes to deal with the challenges of the future."

The seventh and most recent survey, completed by 66 utilities early in 1982, focused on the plans and perspectives of utilities with respect to generating capacity requirements, technologies, business and economic conditions, electrical system expansion, and environmental and siting considerations.

More important than the final tally of

results, which fills a separate volume, is the mosaic of meaning that emerges when one is guided by the interpretation of analysts such as Young and Zeren. "The true usefulness of the survey is to look at the broad categories and how they change from year to year," adds Young. "We look for those areas that have shifted."

The portrait that unfolds contains few surprises about directions of trends to those professionals who follow the daily ups and downs of the utility business, although they might surprise those less familiar with the industry. The breadth and level of intensity of trends are particularly instructive. The following were the survey's key conclusions.

□ Utilities are showing greater interest in more productive use of energy. This means, as Zeren puts it, "more attention is being paid to the customer's side of the meter."

□ Although most utility generation expansion plans rely on conventional pulverized coal, light water reactors, and combustion turbines, the survey revealed an increasing willingness to consider a host of new technologies for generation before the end of this century.

□ Despite its current position as a generation mainstay, nuclear power faces an uncertain future. Business decisions on new nuclear plants will likely remain clouded until important technical and financial uncertainties are resolved or at least diminished.

□ On the other hand, the future role of renewable resource technologies, such as solar and wind, is evolving. A number of utilities expect a small contribution to national electricity production from renewables but only a few utilities, probably in the West, will benefit from their further development.

As for the utilities' response to questions of how well EPRI's R&D program matches the industry's needs, Young takes comfort in the lack of surprise. "The survey told us that EPRI's R&D program is closely in line with utility thinking on what technologies and strategic program areas are most important to them."

But survey results can sometimes lose their impact when compressed into a few summary nuggets. It is the meaning beyond the statistics that intrigues such people as Zeren. "The most interesting indication from the survey to me," says Zeren, "is the departure from traditional views of the industry. The industry views itself much differently than it would if you had run that same survey back in 1975 or 1976.

"In some ways, it's more pessimistic, which is a little disturbing, but I think its whole view of the business has changed considerably," Zeren continues. "The industry is beginning to redefine what its business is, and we see some of that in the survey. Utilities talk about selling end-use goods and services, helping their customers use less energy. They're looking at new kinds of business arrangements to supply the power. There's a real change of tenor."

The trend to greater emphasis on conservation and load management typifies the kind of evolutionary change that only periodic tracking in the survey can point out. "Conservation has moved up in priority ranking over the years and has stayed up," notes Young. "This has helped convince EPRI management we ought to put more money and emphasis on conservation and end-use research—and we have."

In the latest survey, when asked what capacity and energy savings the utilities anticipate from customer conservation measures, the majority of respondents indicated that they expect approximately 2% capacity and energy savings in the next 10 years. In general, the utilities give a number of industrial, residential, and commercial energy conservation measures high marks for cost-effectiveness, and a majority indicated they are, in fact, helping their customers apply such measures. The tools to cut energy use range from insulation and more-efficient lighting systems and appliances to solar-assisted water-heating and industrial waste heat utilization.

A key indicator of the degree to which EPRI's technology R&D matches industry needs is found in questions involving new generating technologies. The responses indicate a ranking of available and not-yet-available systems that range from conventional coal-fired boilers to fusion.

When asked to rank the likelihood of using these technologies in future generation expansion plans, the utilities, not surprisingly, headed their lists with conventional coal plants and light water reactors. The more interesting results lie below this "most likely" group, however. Five generating or storage technologies in whose development EPRI is already playing a central role—fluidized-bed combustion, pumped-hydro storage, gasification–combined cycle, fuel cells, and wind turbines—were "likely" to be used in the future.

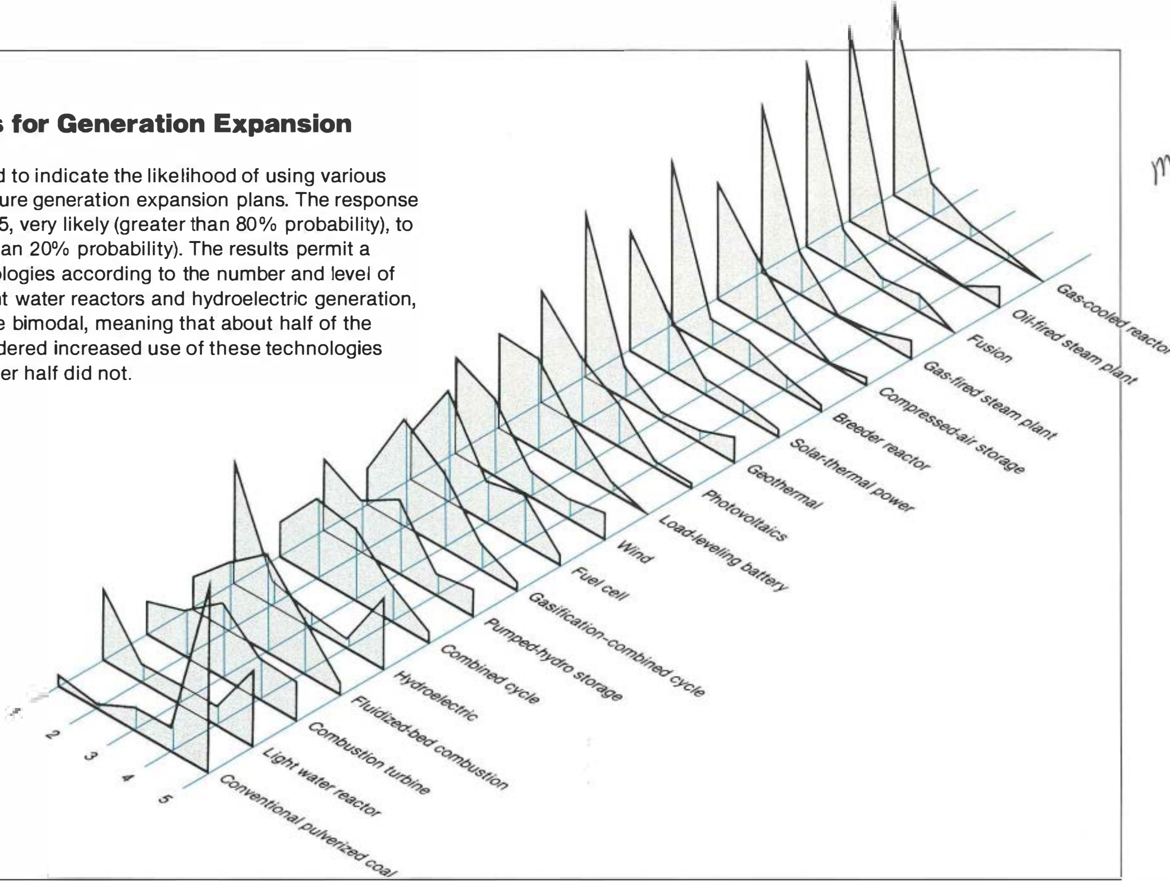
"The survey shows us that utilities are seriously considering using many of the technologies we're working on at EPRI," notes Young. "Even with the perception that the utilities are not planning to build many new units, they still show high enthusiasm for more speculative technologies. When you ask them to put down on paper what their plans are, what their futures look like, it turns out that our program responds well to what they envision needing."

An important caveat was revealed in the utilities' response to ranking the future use of nuclear power, however. The overall response was bimodal, meaning about half of the utilities indicated they are very likely to use more nuclear generating plants in the future, while the other half is not.

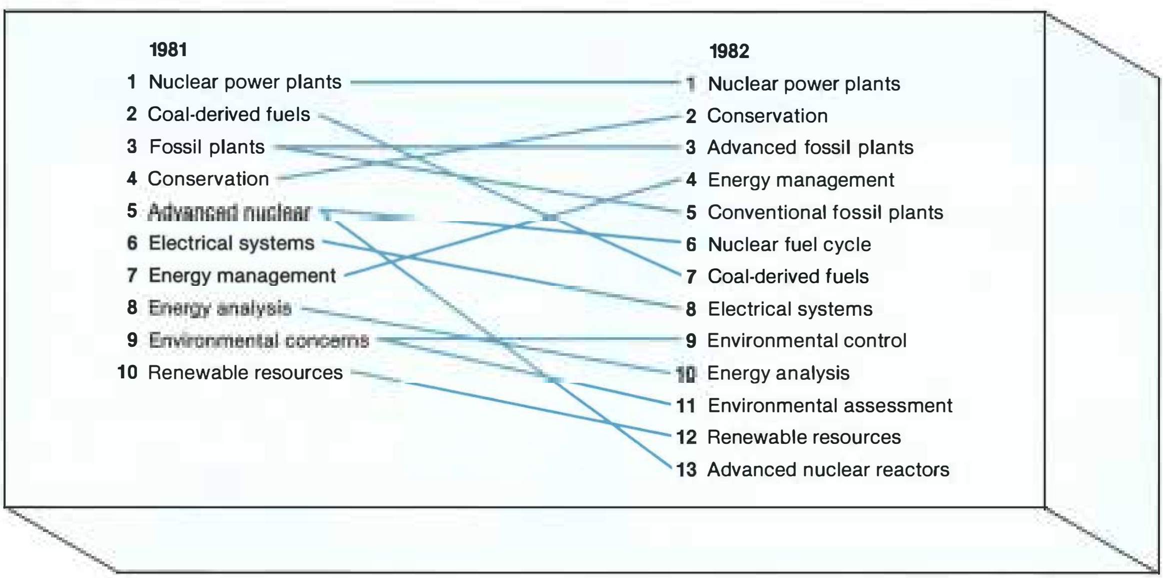
In the responses to a more detailed set of questions regarding the future of nuclear power, additional interesting insights emerged. Only 6% of the utilities who completed the survey (out of a total of 66) indicated they are likely to place new orders for nuclear plants within the next five years; 42% said they thought

Technologies for Generation Expansion

Utilities were asked to indicate the likelihood of using various technologies in future generation expansion plans. The response scale ranged from 5, very likely (greater than 80% probability), to 1, not likely (less than 20% probability). The results permit a grouping of technologies according to the number and level of responses. For light water reactors and hydroelectric generation, the responses were bimodal, meaning that about half of the respondents considered increased use of these technologies likely, while the other half did not.



Utilities were asked for their opinions on where EPRI should put emphasis in its R&D program. This chart compares the rankings of strategic program areas in the 1982 survey with those in 1981. As indicated, the greatest shifts in priority relate to conservation and load management, which moved up in priority, and coal-derived fuels, which moved down. Despite an uncertain outlook for new nuclear plant construction, nuclear power plants and nuclear fuel remain high R&D priorities because of the investment in existing plants. The 1982 R&D priority list is longer because three categories in the 1981 list—fossil plants, advanced nuclear, and environmental concerns—were broken into two categories in the subsequent survey.



Options if Capital Is Limited

(average value of responses*)

Very Likely	
Encourage customer conservation	4.67
Defer retirements	4.35
Buy power from neighbors	4.24
Use load management	4.11
Likely	
Participate in joint ownership of large plants	3.98
Increase availability of existing plants	3.90
Encourage cogeneration	3.65
Install small or modular plants	3.26
Purchase from customers	3.22
Purchase from entrepreneurs	3.02
Moderately Likely	
Reduce reserve margin	2.87
Use novel financing	2.83
Buy from Canada and Mexico	2.52

*Utilities were asked to rate options they would use if capital is limited for new power plant additions. A rating of 5 indicates very likely; 1 indicates not likely.

Environmental Issues Expected to Be of Greatest Concern From 1982 to 1992

(average value of responses*)

Likely	
PCBs	3.86
Acid rain	3.52
Moderately Likely	
Ash disposal	3.20
Regional air quality	3.02
Water quality	2.98
Local air quality	2.95
High-level radioactive waste disposal	2.94
Low-level radioactive waste disposal	2.92
Effects of air pollutants on health	2.65
Toxic substances (occupational)	2.57
Risk evaluation	2.56
Visibility	2.50
Less Likely	
Effects of toxic substances on health	2.28
Scrubber sludge disposal	2.25
Electric field effects (community)	2.25
Ionizing radiation (occupational)	2.10
Electric field effects (occupational)	1.87
Indoor air quality	1.65
CO_2	1.62

*Utilities were asked how likely certain environmental concerns would be an issue for them in 1982–1992.

utilities will begin placing new orders for nuclear plants within 10 years. Ninety percent of those utilities responding felt that most plants now under construction will be completed and operated for their full term.

The survey also provided an opportunity to probe utility interest in synthetic liquid fuels. Coal-derived liquids and shale oil both ranked in the midrange of likelihood when utilities were asked what alternative fuels they might use in existing petroleum-fueled generating equipment over the next 20 years. But utilities appear little interested in owning or developing synthetic liquid fuel plants themselves. Thirty-eight percent said they might invest in such a plant as a participant with other utilities, but only 14% indicated any interest as a sole owner. Reflecting a traditional concern for the most economic approach to energy production, a majority of utilities indicated scant willingness to pay a premium price for synthetic liquids in order to ensure a liquid fuel supply. Nonetheless, more than 60% said political events abroad or rapid escalation of imported oil prices could bring about a significant synthetic liquid fuels industry in this country in the next 20 years.

No survey is needed to learn that capital for new or upgraded utility power plants has been getting more difficult to obtain. But what options are utilities considering for dealing with that challenge? Rated in the survey as very likely options were encouragement of customer conservation, deferred retirement of existing plants, power purchases from other utilities, and greater use of load management techniques. Strategies that were rated likely include joint ownership of large plants, encouragement of industrial cogeneration, and installation of smaller, modular power plants.

Another telling set of results is found in the responses to questions on environmental issues. Utilities were asked whether they thought certain environmental concerns would become significant issues for them within the next 10 years (1982–1992) and beyond. In the near term, PCBs and acid deposition were viewed as the likely chief problem areas. But after 1992, the respondents indicated, ash and scrubber sludge disposal from pulverized-coal plants and high-level radioactive waste from nuclear power plants will outrank acid deposition and PCBs as the principal concerns. When asked to rank those environmental control options that are under consideration for pulverized-coal plants, the utilities rated lime/limestone flue gas desulfurization, electrostatic precipitators, byproduct utilization, and combustion control of nitrogen oxides at the top of the list.

Siting constraints pose special problems often unique to individual utilities trying to build new power plants. The survey's ranking of categories of constraints gives useful feedback to an R&D organization trying to help smooth the selection of new sites. Utilities rated air quality, water availability, and public perception as their chief siting constraints, although water quality, solid-waste disposal, and land-use conflicts were rated close behind.

From these and more-detailed results generated in the survey, EPRI management obtains a regular reading of the industry's pulse, a glimpse of what is on the minds of dozens of utility executives and managers. Although the results are quite detailed statistically, in some cases broken down by regions, their prime value to EPRI is qualitative, explains Zeren. "We don't take a numercial score generated by the survey and stick it in some kind of formula to generate the R&D budget. We don't think that such a formula exists. But in terms of qualitative application, if you were to trace how certain topics in the survey change over time and then trace how EPRI's program has changed over time, you'd see a strong correlation. This is not to discount the quantitative data entirely; they do help us estimate the usefulness of individual R&D activities."

To judge from the response rate of utilities asked to complete the survey, EPRI is not the only place where the survey process is taken seriously. "We have the most dedicated clientele anywhere for surveys," says Young, noting that the 83% overall response rate (66 out of 80 utilities) is about two and a half times better than the 30% that is usually considered a good return for such an elaborate poll.

"The utilities show a real interest in providing input to EPRI, so the response rate is much greater than is normally found for a survey of this length," comments Sherman Feher, an EPRI planner who analyzed the responses. "We were told by several utilities that in the course of writing the corporate response, the questions generated some new thinking in terms of the company's own strategic planning."

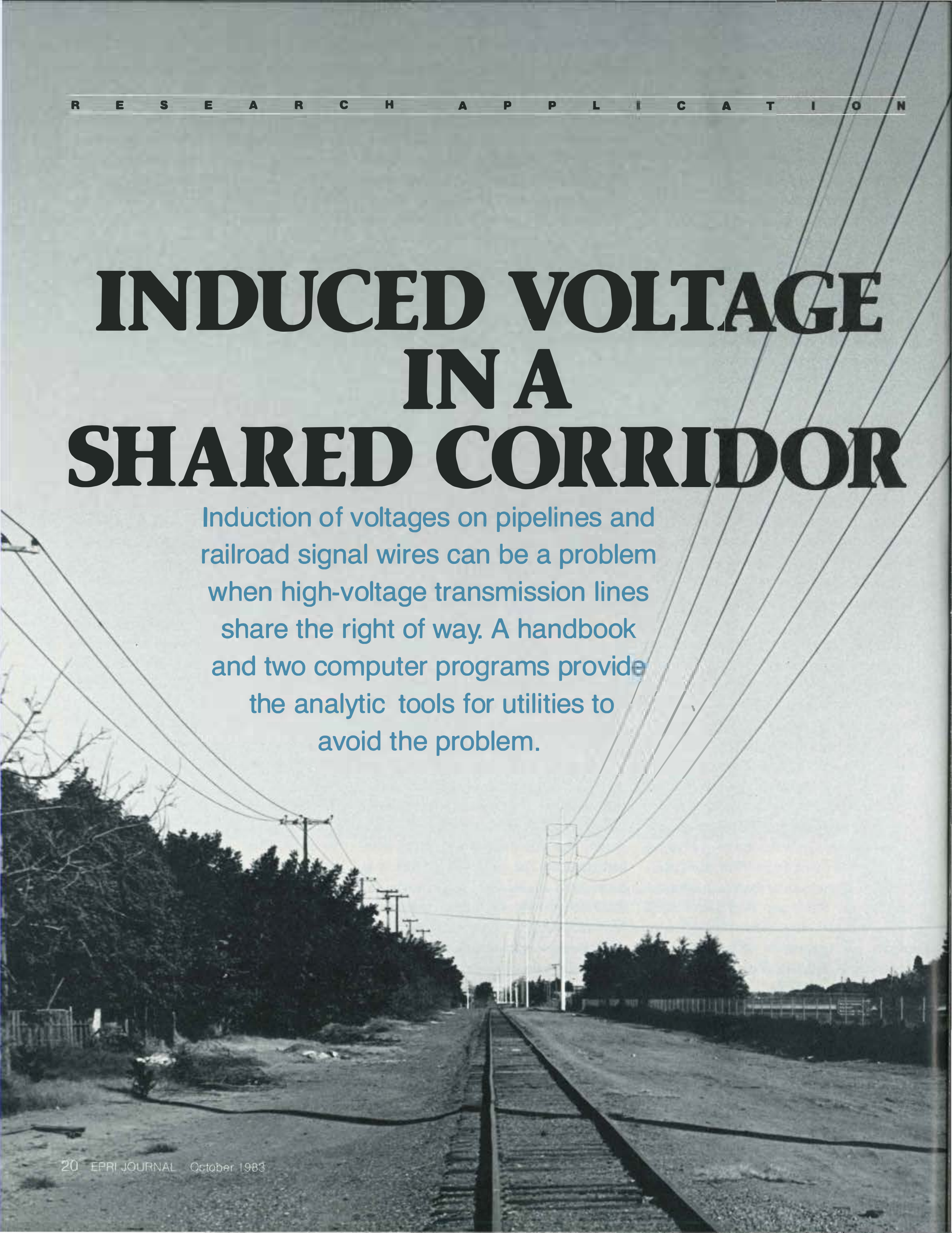
One utility executive who confirms Feher's point is Carl Weinberg, director of research and development at Pacific Gas and Electric Co., San Francisco. Weinberg says that boiling down the input from many PG&E staff to prepare the company's survey response "generated a great deal of discussion and thinking on our part about the direction of where things should go and what positions the company should take."

Most utilities, of course, already do considerable strategic planning, but as Weinberg points out, "Most of that is done in a somewhat different context. The EPRI survey forced us to look at things in terms of what research needs to be done. That sharpens issues in your mind in a new way." Weinberg calls the survey results "the one place where you can get a sense of what is on the whole industry's mind. There is no other forum like that that I know of." ■

This article was written by Taylor Moore. Technical assistance was provided by F. S. Young and Sherman Feher, Planning and Evaluation Division.

INDUCED VOLTAGE IN A SHARED CORRIDOR

Induction of voltages on pipelines and railroad signal wires can be a problem when high-voltage transmission lines share the right of way. A handbook and two computer programs provide the analytic tools for utilities to avoid the problem.



carcity of land for new power line rights-of-way, environmental resistance to new routes, and the numerous attendant government regulations are making it increasingly difficult for electric utilities to choose a route that is acceptable to all concerned. Consequently, high-voltage overhead transmission lines are more frequently sharing common corridors with some uncommon bedfellows: a railroad, for example, or pipelines transporting gas, water, or petroleum products. Even in a desert, where land might appear to be readily available, preservation of the natural habitat is of major concern. There, as well as in congested areas, a single, shared right-of-way is sometimes the only transmission line route the utility is permitted to take.

But sharing a corridor can create problems brought about by magnetically induced voltages. The electric current that runs through a transmission line creates a magnetic field around the overhead power line, a field that extends to other conductors in proximity, thus causing current to flow through a pipe or a railway signal wire. Without mitigation, it is possible that this induced current could result in voltages that exceed established safe limits. Because the magnetic field diminishes rapidly with distance from a power line, the magnitude of the induced voltage also falls off rapidly with distance. Half a mile away, effects would be too small to be of concern.

Historically, controversy arising from proposals to share rights-of-way wound up in lawyers' hands. Often, this was due to lack of adequate technical information. Today's research can provide solutions without contention, but essential to such resolution is cooperation among the organizations involved. Four EPRI projects that demonstrate this common effort brought together electric utility, gas, and railroad representatives and produced two final reports, a handbook, and two computer programs—significant tools for analyzing induced-voltage problems. Effective, less costly mitigation techniques were also identified and developed.

The American Gas Association (AGA), through its Pipeline Research Committee, cofunded two projects with EPRI totaling $753,000; these resulted in the *Graphical Analysis Handbook* (EL-3106, Vol. 2) and the computer program PIPELINE. The handbook, designed for use in the field, is a consolidation of known data on the mutual effects of power lines and pipelines and contains graphic techniques for quick calculations. Its information can be applied to any pipeline, regardless of the product being transported, according to John Dunlap, EPRI project manager, Electrical Systems Division. The handbook can be ordered from the Research Reports Center, P.O. Box 50490, Palo Alto, California 94303.

The computer software for pipelines, uncomplicated and straightforward, is especially user-friendly and can be applied by people with limited experience in such analyses. Given the basic data on the characteristics and size of pipes, type of coating, and conductive nature of the soil, the program—within a few minutes—can accurately calculate the voltage induced on the pipe for situations on shared rights-of-way. After the voltage and current are calculated, either by the computer program or by using the graphs in the handbook, the EPRI project's final report (EL-3106) can be consulted for mitigation techniques that can be used to reduce these voltages to acceptable levels.

A typical strategy is to ground an induced voltage, but in some areas a good ground is almost impossible to achieve. The EPRI–AGA research, through the pipeline computer program, developed another mitigating method in a Mohave Desert project, just east of Barstow, California, where a 500-kV line and a gas pipeline run parallel for many miles. Near the middle of this section, the transmission line phases are transposed, creating a voltage rise on the nearby pipe. To mitigate the current, a wire about an inch in diameter (a piece of transmission conductor, for instance) is buried parallel to the pipe. A voltage is induced on this wire, just as it is on the pipe; however, the wire is positioned so that the voltage is of opposite polarity to that on the pipe. The pipeline and wire are connected, a technique that cancels the voltages, reducing them to an acceptable level. Depending on the length and specific situation of a shared right-of-way, the buried wire length can vary from a half mile to as much as five miles (0.8–8 km).

At least one utility has demonstrated the economic value of the EPRI analytic tools. Southern California Edison (SCE) was able to calculate the induced voltage and plan for its mitigation when it proposed to build a 240-mile (386-km), 500-kV transmission line that would parallel a gas pipeline for 58 miles (93 km). Using the technical tools developed in the EPRI research, the power company and the pipeline company agreed on a mutually acceptable design. This meant the utility could plan to share the pipeline right-of-way, avoiding an additional 12 miles (19 km) that an alternative route would have required. SCE estimates a savings in revenue requirements of more than $3.5 million from building the transmission line on the preferred route.

The other computer program also available is TRAIN, a software package that can compute the voltages and currents induced on the tracks and on railroad communications and signaling (C&S) systems near an overhead transmission line. A railroad track system is divided into sections or blocks. The signal, its wires mounted on poles and connected block to block, tells a train engineer if there is a train in the block ahead. However, the induced voltages from a parallel overhead transmission line can cause signals to malfunction; because the system is designed for a fail-safe mode, a malfunction causes all signals to flash red, shutting down traffic. Although the fail-safe feature removes the accident potential, the more typical results are disruptive and expensive delays for passenger and freight trains.

The voice communication circuits on overhead signal wires often are the part of the railroad system that is most sensitive to power line interference. Sometimes the communication system can be converted to carrier circuits whose frequency range is above that of induced interference. A popular, often cost-effective solution is conversion to microwave transmission, a method of voice communication that eliminates the interference problem.

Another promising future solution to the railroad block signal problem is the electronic track circuit, which eliminates overhead signal wires altogether. These circuits, which use the rails as conductors to transmit their pulses from track section to track section, hopefully can be designed to be insensitive to induced voltages. Preliminary tests show further development work on electronic track circuit equipment is needed. Other C&S mitigative methods recommended by EPRI research include shortening the block length, using filters at signal relays to dissipate the interference level, and burying the signal lines. Of course, in some cases, interference is not great enough to require any mitigation; the software programs can establish this outcome too.

TRAIN, PIPELINE, and the analysis handbook provide the analytic techniques for confronting problems of induced voltage, but the configurations and interested parties involved in each situation are different. For example, one corridor in the Southwest, now the subject of an EPRI study, is shared by a high-voltage transmission line, a pipeline, and a railroad. Finding solutions that all participants can live with is the central goal when uncommon bedfellows share common corridors. The EPRI projects have provided an approach for dealing with the technical problems, with significant achievement in tools and cooperation. There is more that can be done, particularly in the corridors shared by electric utilities and railroads. But the beginning step has been taken; the door to cooperative research is open. ■

This article was written by Rosalyn O. Barry, science writer. Technical information was provided by John H. Dunlap, Electrical Systems Division.

Paul Joskow: Accent on Economic Efficiency

A leading specialist in government regulation and member of EPRI's Advisory Council recommends that the industry take advantage of "breathing space" now to implement reforms that will serve the industry and the country well into the future.

Within the energy community and particularly within utility circles Paul Joskow is perhaps best known for his work in the area of public utility regulation. The 36-year-old economics professor at the Massachusetts Institute of Technology is coauthor of a book published by MIT Press this summer that examines the prospects for deregulation of various aspects of electricity supply and pricing and makes suggestions for how and under what conditions this might be attempted within the industry. However, *Markets for Power: An Analysis of Electric Utility Deregulation,* written with colleague Richard Schmalensee, is broader in its orientation than its title might imply.

"Although deregulation was the motivation behind our work, the book is really about the electric power industry in general—how it should be structured and how it should be regulated," explains Joskow. "We look at various alternative notions of what deregulation for the electric power industry means and try to compare them with deregulation in other industries. We also spend a good deal of time discussing potential regulatory reforms and changes in the structure of the electric power industry that might lead to lower costs and prices in the long run."

Like his book, Joskow's own orientation toward industry issues is broader than might be commonly recognized. His research and published writing span a broad range of industry topics: from synfuels to nuclear power; from cogeneration to utility finances. In addition to numerous articles in professional journals, Joskow is also coauthor of *Electric Power in the United States: Models and Policy Analysis,* published by MIT Press in 1979. He has served as a consultant on energy issues to the U.S. Department of Energy and is a special consultant to National Economics Research Associates. For two

"Sustained economic growth can only become a reality if the United States can increase productivity. And greater productivity will require better educated, more highly motivated workers. It will also require innovative management, capital investment, and technologic innovation."

years he served on the Administrative Conference of the United States, which was established by Congress to provide advice for improvements in administrative law and regulatory procedures, and for the past three years he has been a member of EPRI's Advisory Council, the group of leaders from outside the utility industry that provides advice to EPRI's Board of Directors, officers, and staff on the emphasis and direction that the Institute's research program should take to meet the broad needs of society.

In a recent interview in EPRI's Washington Office, Joskow discussed a broad range of energy and economics topics. His comments underlined a basic middle-of-the-road approach to the economic and technical issues that affect the electric utility industry. A persistent theme that runs throughout his comments is that economic efficiency is the primary goal that should be sought when setting policy and making decisions regarding issues that affect the utility industry.

It is, in fact, the central tenet of his recently published book. He and coauthor Schmalensee evaluate current industry practices on the supply and pricing of electric power according to two efficiency criteria: first, is electricity being supplied at the minimum possible cost, and second, do electricity prices appropriately reflect the costs of electricity supply? They use the same two criteria to evaluate proposed regulatory and structural changes to the system, asking whether different practices would likely lead to more efficient prices and costs. It is on this basis that the authors analyze several possible scenarios for deregulating the industry—that is, replacing price and entry regulation with the regulatory forces of a free market.

"Where we came out was that deregulation is not a panacea for the electric utility industry. The kind of deregulation model that was applied to the airlines, the trucking industry, and even to the telecommunications industry is not really relevant here." The authors spend considerable time examining the technical, economic, and institutional forces that have shaped the industry. They emphasize that the industry is characterized by unique and complex features that make casual analogies to other industries for policy purposes very dangerous.

What the authors suggest is that the industry should move forward slowly with some changes that would result ultimately in a mixture of continued economic regulation at some levels and increasing competition at others. Specifically, retail rates and entry into the distribution market must continue to be regulated. The primary focus for replacing regulation with free markets should be at the wholesale power level. However, even here deregulation cannot necessarily be complete, nor should it be undertaken too quickly. Change is liable to be costly and complex, and the ultimate outcomes are uncertain. The authors present a list of possible changes that could be undertaken slowly to move the industry toward increased efficiency without totally resolving the precise role that deregulation should play.

Some of these suggestions include basing wholesale rates on marginal-cost-pricing principles, encouraging more power pooling and coordination, encouraging utilities to establish financially independent generation and transmission companies within a holding company framework, encouraging mergers of small utilities, and experimenting with deregulation of wholesale market transactions.

"If deregulation is to play a role in helping to improve the efficiency with which electricity is produced and utilized, it must be introduced as part of a long-term process that also involves regulatory and structural reform," the authors maintain. "In this way, we will get results more quickly and end up with a more efficient electric power system in the long run than if we either muddle through with the status quo or suddenly remove most regulatory constraints on prices and entry and impose drastic structural changes."

Economic trade-offs

This accent on efficiency is basic to Joskow's own personal makeup and to his choice of economics as a field of endeavor. He says that economics offers him the opportunity to study what he believes is the most difficult problem to face society—how to get the most out of scarce resources. "It's difficult because it involves trade-offs between competing demands on society's scarce resources. What makes it fun for me is to be involved in problems that arise in the real world." He believes such involvement is essential for someone like himself who specializes in how industries are organized and regulated.

"To bridge the gap between academia and the real world you have to get out of the ivory tower," he says. Joskow himself serves as a regulator in his hometown of Brookline, Massachusetts, on the Historic District Commission that approves changes in town structures. "I have much more sympathy for regulators after a couple of years of doing that," he comments.

Although Joskow comes by his interest in economics naturally (his father is an economist), his commitment to the profession was not made until college years. He grew up in New York City and attended public schools there. When he entered Cornell University as an undergraduate in the mid 1960s, his original goal was to become an electrical engineer. His ambitions were changed, however, by a course in economics that he took at Cornell and by the man who taught it. In later years, Joskow would follow in this professor's footsteps in more than one respect.

The professor was Alfred Kahn, a specialist in government regulation in industry, who as chairman of the Civil Aeronautics Board in the late 1970s presided over the deregulation of the airline industry. It was through Kahn that Joskow developed his interest in government regulation and industrial organization. Kahn was also very involved in utility industry affairs, as is Joskow, and for a while served as chairman of the New York Public Utilities Commission. In this capacity, he, like Joskow, served as a member of EPRI's Advisory Council.

Joskow pursued economics throughout his undergraduate education and graduated Phi Beta Kappa in 1968. He also won a Woodrow Wilson Fellowship and a National Science Foundation Graduate Fellowship. He graduated from Yale University with a Master's degree in economics in 1971 and a PhD in 1972. He has taught economics at MIT since 1972 with one year's absence as a visiting professor at the John F. Kennedy School of Government at Harvard University, 1979–1980. With Joskow's background in economics, his experience with utilities, and his specialty in regulation, he is certainly well qualified to discuss current economic issues of critical importance to the industry.

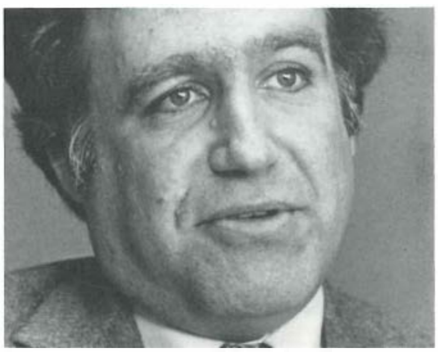
"I think the electric utility industry, perhaps more than any other, has a profound interest in economic stability in terms of a sustained rate of economic growth, stable prices, and low interest rates," he comments. "The 1970s were a disaster for utilities for a number of reasons. Interest rates were rising rapidly, inflation was high, and regulatory commissions were not enthusiastic about granting rate increases. And this was happening at a time when utilities' own input costs were rising. They were moving toward a much more capital-intensive technology—toward nuclear power and

"I'm not one who believes that the future of the U.S. economy is in making Pac-Man games. I don't see our economy moving entirely to a service or high-tech economy. . . . I don't think that the industrial base of this country is going to disappear overnight."

coal plants with all kinds of environmental restrictions."

What about the next 10 years—what will they bring in terms of the basic health of both the economy in general and the utility industry in particular? Joskow is optimistic, but cautiously so. He believes that both the economy and the industry are in better shape today than they were a few years ago and are currently experiencing what he calls breathing space between the tumultuous economic events of the recent past and the uncertainty of the future. But the situation is tenuous.

"The economy appears to be in a state of recovery and I think it can be a sustained recovery, but it is not as broad as some might like, and it is still fragile," he maintains. "The breadth and duration of the recovery depend on various government policies, especially on federal reserve policies, on what happens to oil prices, and on our ability to improve productivity."



"Deregulation is not a panacea for the electric utility industry. The kind of deregulation model that was applied to the airlines, the trucking industry, and even to the telecommunications industry is not really relevant here."

Joskow believes that inflation should remain under control this year at about the 4 or 5% level and that this will be of critical importance to the utility industry. "Inflation is a disaster for any regulated industry," he explains. "If you have to have your prices approved by a regulatory commission when everyone else can simply raise theirs without government approval, you're caught in a squeeze."

Joskow feels that the industry has benefited from substantially lower inflation rates and from lower interest rates, although progress on the interest rate front has not been as good. "Interest rates have come down, but the *real* interest rate—that is, the difference between the rate of inflation and the nominal interest rate—is still very, very high by historical standards," he explains. "This means that the real cost of capital is still very high, a situation that particularly affects the electric utility industry. High interest rates result from monetary policies that reflect a continuing concern about renewed inflation and concern over budget deficits.

"It makes sense to run a deficit when the economy is slack to try to stimulate it," he says. "The problem arises when the economy recovers and the deficits never disappear. That can't go on forever, because it means that the government is going to be dipping into the capital market for large amounts of money, keeping interest rates up, and generating renewed inflation. Something is going to have to give." Joskow believes that the government will have to raise taxes or cut defense spending to remedy the situation, probably both.

Joskow believes that unemployment (now running about 10%) will stay high for this year and possibly into next, but then should begin falling much more quickly than it has so far this year. "That's something that always happens when you start a recovery. The first thing that companies do is to use their existing workforce more intensively. Then, as the recovery appears to be sustainable, companies go out and hire new workers. And it looks like we're moving into that stage. Factory utilization is up in the critical industries like the automobile and steel industries."

Joskow is not one who believes in the theory, currently popular in some economic circles, that the older, more established manufacturing industries in the United States have declined to the point that they are no longer viable here and will soon move overseas completely. Replacing them in terms of economic importance, so the theory goes, will be the high-technology industries—computers, robotics, information services, and the like. Although Joskow sees an important role for the new industries in the economy, he feels the "de-industrial revolution" theory is too extreme.

"The changes we are seeing are part of a long-run evolutionary process," he asserts. "I'm not one who believes that the future of the U.S. economy is in making Pac-Man games. I don't see our economy moving entirely to a service or high-tech economy. I do think that this is where the growth is and this is where a lot of the new employment is going to come from, but I don't think that the industrial base of this country is going to disappear overnight. We'll continue to make cars in this country, continue to make steel, and continue to manufacture products generally, but these industries are never going to be what they were in the past either in their dominance of the U.S. market or in the way they produce things."

Joskow feels that we may see more and more joint ventures between the United States and other countries in manufacturing certain products. Increasingly, U.S. companies are going to have to compete in world markets and to adapt to changing conditions if they hope to survive. Both plants and workers will have to become more efficient and more productive. "Sustained economic growth can only become a reality if the United States can increase productivity. And greater productivity will require better educated, more highly motivated workers. It will also require innovative management, capital investment, and technologic innovation." Joskow believes that the high-tech industries will be a source of that innovation.

Uncertain demand

What will be the effect of these changing economic conditions on the future demand for electricity? Joskow takes a middle-of-the-road approach. "Energy end use has been shifting from other fuels to electricity since the beginning of the century. I think this shift will continue and that electricity demand will increase more rapidly than the demand for energy generally, but I don't think we are going to see a return to the very rapid rates of growth in electricity consumption that occurred during the 1960s. One of the reasons for this," he contends, "will be the greater energy efficiency that will characterize the nation's new capital stock."

He is quick to point out that growth rates will vary tremendously between areas of the country. "It's very dangerous to look at national averages in a country as big as the United States," he says. "Regions have different industrial mixes, different climates, and different histories in terms of energy prices and economic growth. The Pacific Northwest, for example, may see a negative growth in electricity consumption because electricity rates there were very low historically and are now rising quickly to reflect the high costs of incremental supplies. The Midwest has a lot of excess capacity and we're not sure what will happen to the economy there in the industrial heartland. In the growing areas of the South and Southwest we may actually see a return to the substantially higher rates of electricity demand."

There is no way to predict demand with certainty, he concedes. It depends on the vagaries of economic growth, on oil prices, and on the nature of the changes that take place in the composition of the economy. Because the utilities face a future of uncertainty, he believes that they must maximize their efforts to remain flexible. And he believes that this is happening already in the industry.

"Most utilities are going to be more cautious in the future about building new power plants, especially large power plants. I don't see any utility in this country making a commitment to build another nuclear plant in this decade, for example. We will probably complete a large fraction of the plants that are already in the pipeline, but I don't see any more for a while. The major interest for the industry now is in getting that very expensive capital stock to work, to work well, to work safely, and to work for a long time.

"In the coal area, I see a return to much smaller units—units in the 300–500-MW range. During the 1970s many utilities built very large, sophisticated coal units, and they discovered several things. First, these plants are very expensive. Second, they didn't always work as well as expected. And third, they were not terribly well adapted to periods of tremendous uncertainty about demand. So I believe that future coal plants will be smaller, and I think we'll see a lot more cooperation among utilities in financing those units, in sharing the risks, and in sharing the power."

Joskow also believes that utilities will want simpler technologies that require reduced construction time. He feels that they will want to keep their old power plants running as long as they can and that they will be much more enthusiastic about encouraging conservation and such practices as industrial cogeneration.

"Essentially, it's an effort to stay flexible, to recognize that there's uncertainty, and to try to spread the risks among a number of entities," he observes. "The mood of many executives in the industry now is that the best thing that could hap-

"We muddled through the 1970s. We didn't know how to deal with conflicting assumptions about demand growth, about costs and capital estimates, about solar energy and cogeneration. Now we have a breather if the economy stays stable."

pen is to never have to build another power plant. I think the industry is looking for some breathing space after the problems of the 1970s."

On the whole, he believes that the industry does have this breathing space today and is in much better financial shape than it was two years ago. "Right now in most regions of the country the industry appears to have rather substantial reserve margins compared with traditional planning levels, and it looks as if those margins will remain adequate for several years into the future. Construction programs have stabilized and earnings are up for a number of utilities."

On the average, Joskow feels that utility rates are still a little low but are moving in the right direction. He hopes that regulators have begun to realize that there is a trade-off between lower prices in the short run and higher costs in the long run and that they recognize they have to provide utilities with an appropriate rate of return on their investments to encourage least-cost supply.

He believes that regulators and industry officials alike should take a sober look at the 1970s and attempt to institute needed reforms. "We muddled through the 1970s," he asserts. "We didn't know how to deal with conflicting assumptions about demand growth, about costs and capital estimates, about solar energy and cogeneration. Now we have a breather if the economy stays stable. I'm a great believer in rational planning that looks at the long-run consequences of private and public decision making. Too many public policy decisions were made in the 1970s that reflected only short-run costs and benefits. I hope that during the 1980s the industry and government will take this opportunity to move forward with regulatory and rate reforms and possibly with reforms in the structure of the utility industry that reflect some of the things that we have learned in the last decade."

Opportunities for EPRI

In addition to regulatory and structural reform, Joskow believes that the industry should move ahead with new technology to increase the efficiency of electricity production, transmission, and use. He sees tremendous opportunities for EPRI, as the primary source of research and development for the industry, to bring about this change through its programs.

Joskow has served on EPRI's Advisory Council for the past three years and in this capacity has had the opportunity to observe and evaluate the Institute's changing and growing program. What does he feel is EPRI's main challenge for the next decade? "It involves the identification of the kinds of research and development needs that are going to have to be fulfilled to meet the utility industry's problems in a world of tremendous uncertainty about what the future is going to be like," he states. "I think the hardest job for EPRI will be to find ways to allocate its scarce resources to respond effectively to a wide range of potential problems. Although EPRI has to be responsive to the short-run problems of the industry, it is going to continually face a problem of trying to reserve some fraction of its budget for longer-run research that focuses on more speculative, distant problems. I think there's going to continue to be a tug of war between the two."

To meet this challenge, Joskow believes that EPRI will have to remain flexible. "I think that EPRI, like the utility industry, is going to have to hang loose in a sense. Things are changing fast; there's a lot of uncertainty; and I think EPRI is going to have to be ready to switch resources from one area to another as new opportunities and needs are identified. That may mean dropping some research projects that appear promising but perhaps have a lower payoff than others."

It may also involve more and more sharing of research activities with particular groups of utilities that have a special interest in a given area. This is particularly true regarding some of the large projects that have been deferred or cancelled by the federal government and are of importance to some segments of the industry. "Rather than having EPRI try to fund these projects through general receipts, I'd like to see a continuing effort to create groups of utilities or joint groups of utilities and manufacturers to fund specific projects. That way you get to see what the utilities really value when they are asked to put their money on the line for specific projects. In this way EPRI can be both a source of funding and a research coordinator for the industry."

What about Joskow himself? What challenges and opportunities does he see ahead during the next decade for himself, both as an economist and as an individual? In his personal life Joskow and his wife Barbara are excited about a new challenge—raising their first child, a daughter, born this summer. Joskow says he is ready for a breather from intense academic involvement to devote attention to parenting.

"I finished my PhD when I was 24, and I was a full professor by the time I was 30," he says. "I've worked hard and been very busy, and I deserve a little time off to enjoy a child."

As an economist, he is also ready for a breather. Although he believes that his future ultimately lies in the academic world, he is ready for a change and would like to explore opportunities in the government arena, pursuing what he loves and does best—tackling real-world problems with an eye toward increasing economic efficiency. ■

This article was written by Marie Newman and is based on an interview with Paul Joskow.

NASA Brings Space Technology Down to Earth

Long at the forefront of technologic developments for advanced space applications, NASA also provides technical expertise for terrestrial energy systems.

America's air and space program dates back to 1915 when Congress created the National Advisory Committee for Aeronautics. NACA's charter was to pool talent from government agencies and from the infant aeronautics industry pioneered by the Wright brothers a decade earlier. The committee was to devise a program to provide a research base from which the nation could gain a position of preeminence in aeronautics. That effort gave birth to the early aviation research centers—Langley, Lewis, and Ames—which are now the heart of NASA's aeronautics research program. "Then when the Russians sent Sputnik into space in 1957, the U.S. Congress reacted by passing legislation that created NASA," explains James Beggs, administrator of NASA. "The new space agency was directed by Congress to pursue frontiers in aeronautics, to establish and maintain U.S. supremacy in space, and to apply its research for the benefit of mankind." This last mission was particularly farsighted in that it established a valuable link for making practical use on Earth of technologies developed for space exploration.

For example, the agency is currently developing orbital systems to help us better manage Earth's resources, analyze the causes and effects of natural disasters, improve understanding of the environment and how it is affected by human actions, and process materials in space to create products that cannot be manufactured on Earth. Although many of these projects do not directly relate to the vision of the space shuttle circling Earth, they are components of NASA's technical research program. Another research area of importance that NASA is tackling involves advancing the nation's technology base to meet future needs for electric power.

Energy in Space

Just as we on Earth depend on electric energy, so do space systems. To provide electric energy in this unique environment, NASA's Space Energy Systems Office directs research and development for space energy conversion. Managed by Jerome Mullin, the office is engaged in photovoltaic, electrochemical, and thermal-to-electric conversion; energy storage; power systems management and distribution; and advanced energy concepts programs. The development of these various energy systems is being considered for both civil and military applications. According to Mullin, "Our research program ranges across the board in space energy conversion. We're in the business of exploring alternatives in order to isolate the critical issues associated with each new technology and then doing the research necessary to resolve them."

Two newer technologies being adapted for electric utility systems have long been used for space application: fuel cells and solar cells. The fuel cell is a very effective system for limited energy requirements in space and is admirably suited for use in vehicles like the space shuttle. When energy needs on a space vehicle begin to expand, however, the weight of the system increases substantially because the fuel cell's reactants (chemical substances) must be carried along with the cell. Although solar array systems are not subject to the weight problem in providing electric power, they have their own limitations. "Solar energy cannot be used in distant regions of the solar system where there isn't sunlight," Mullin remarks.

There are other obstacles to employing energy sources in space; some of these are similar to problems experienced on Earth, such as concern about exposed high voltages. Others are unique to the aerospace environment. For example, electric arcs may be generated in the dilute plasma of lower Earth orbits and cause damage to the space power system. These same arcs can also cause signals to propagate and influence other subsystems on a spacecraft. "When in a very high, or synchronous, orbit another phenomenon occurs—spacecraft charging. This phenomenon, attributable to the solar wind, will cause the spacecraft to undergo very large voltage swings and temperature changes. We spend a considerable amount of time developing mathematical models that predict the behavior of spacecraft involved in a charging event, in what is called the geomagnetic substorm environment. We are also developing models of low Earth orbits to predict the behavior of these systems in plasma environments," explains Mullin.

Grappling with the space environment and the restrictions it presents is only one component of the program. NASA is also trying to solve another: the energy crisis in space. Mullin comments, "It's a real crisis in the sense that we've had 20 years' experience with relatively low power systems—certainly no larger than those found in the average home. To gain much higher power levels, we must deal with the same considerations as a terrestrial utility, such as the numbers of users and the tolerance to abuse."

Nuclear Systems

Large solar arrays are considered to be the primary approach to attain these higher power levels, and considerable research is being conducted on improving this technology. NASA is also reconsidering the use of nuclear reactors to power space systems. NASA's preliminary interest in nuclear-powered systems began in the 1950s with SNAP (systems for nuclear auxiliary power). Those used in space to date employ radioisotopes for fuel and involve very low power levels. Initial interest in higher power reactor systems waned in the early 1970s because of the absence of clear applications. Recently, however, a triagency agreement among NASA, the Department of Defense, and the Department of Energy (DOE) rejuvenated the space nuclear reactor program. SP-100, a 100-kW nuclear power system concept, was signed into agreement in February 1983 at a funding level of $11.4 million for FY1983. Its genesis stems from research and technology conducted at NASA's Jet Propulsion Laboratory in Pasadena, California, and at Los Alamos National Laboratory, where initial requirements based on planetary missions were established, as well as the conceptual designs of the system, reactor, heat transport, and thermoelectric conversion.

Why were nuclear reactor power systems reconsidered as an option for space application? Nuclear, when used in conjunction with electric propulsion, has a principal advantage of very high speed, permitting short flight times to other planets. It can provide a great deal more power per unit of mass than its competitors; its generation life is in the 7–10-year range; and its reliability is expected to be high. "Nuclear systems offer significant advantages in being able to operate in areas of space that up to now were really forbidden to us," explains Mullin. For example, the intense radiation in the Van Allen belts precludes the use of solar arrays under present designs. Nuclear systems, by their very nature, are designed to tolerate radiation. Mullin continues, "Nuclear can be used where solar can't—on the dark side of the moon, for example, where there is a 14-day night. Also, because a reactor system is solar-independent, it does not require batteries for operation in Earth's shadow, it can be used for deep-space applications, and it need not be oriented toward the sun."

Employing nuclear energy for space applications is one example where a land-based energy system has use for space travel. In other aspects of NASA's research program, the opposite transfer of knowledge is occurring. Specifically, the NASA staff is bringing its technical expertise to bear on the energy problems of Earth.

Terrestrial Applications

In the early 1970s NASA's directive of maintaining aeronautic and space supremacy was extended to include national energy concerns. As Beggs explains, "We were drafted during the energy crisis to use our unique research resources to contribute solutions to the nation's energy problems." In response, NASA created the Energy Systems Office to encompass terrestrial use of energy resources. In cooperation with various other federal entities, including DOE, the Department of the Interior, and the Agency for International Development, NASA identified emerging energy technology requirements and determined which of its research centers could best pursue the needed research.

NASA currently participates in about 40–50 active terrestrial projects covering a number of energy technologies. These include photovoltaic energy conversion, solar-thermal electric power systems, energy storage, advanced automotive gas turbines, Stirling and heavy-duty diesel engines, electric hybrid vehicles, and phosphoric acid fuel cell systems. All these projects, however, were undertaken with the stipulation that program direction and research funding were to be provided by the sponsoring agency.

For example, NASA has been managing DOE's large wind turbine research efforts since 1974. The space agency is currently engaged in a project designed to test several MOD-2 wind turbines, each in the 2.5-MW range. NASA is now working on two separate MOD-5 designs—one at 3.5 MW and the other at 7 MW. Compared with the MOD-2 design, both have the potential for reducing electricity costs by 35%. Still in progress, the project is managed by NASA's Lewis Research Center.

On completion of a terrestrial energy agreement, such as the one for the wind project, NASA turns over the research results to the funding agency. Rex Miller, special assistant for Energy Programs and manager of the Energy Systems Office, explains, "We try to conduct projects that have built into them an effective mechanism for demonstrating that the technology is developed in such a way that industry can use it."

The further involvement in terrestrial energy developments by NASA, however, has been limited by a new agency policy. The space agency currently will not renew or accept additional responsibility for any energy-related projects unless the work is shown to be synergistic with NASA objectives. Therefore, NASA will be winding down its remaining projects within the next three or four years. In spite of this new policy, Miller expects $100–$115 million to be transferred to NASA this year from outside agencies in pursuit of energy projects.

Technology Transfer

One energy project that does qualify under the new policy is the agency's research into fuel cell technology for electric energy, which transfers space technology to Earth application. Miller points out, however, that the fuel cell used in space is quite different than that on Earth. "In space, we use pure hydrogen and oxygen to work the fuel cell. On the ground, fuel cells must be able to accept carbon monoxide from fossil fuels." Although there is a difference in its mode of application, there is a similarity in the electrochemistry technology.

The terrestrial fuel cell program also is involved in utility applications. There are two major programs currently under way with Westinghouse Electric Corp. and United Technologies Corp. The Westinghouse program is building toward a 7.5-MW power plant, while the UTC entry is an 11-MW plant. NASA is also involved with DOE and the Gas Research Institute in testing 45 power plants of 40 kW each at various gas utilities.

Another example of a utility-applied spin-off from NASA work is the use of liquid hydrogen. Because of its unique characteristics, including light weight and the fact that it produces far more energy per pound than other rocket propellants, liquid hydrogen was selected by NASA for use as the fuel for the Orbiter, Saturn V, and Apollo rockets. Today liquid hydrogen is used by electric utilities in sulfur-removal processes and for cooling large generators, motors, and frequency changers.

A further outgrowth of NASA's aerospace technology is the use of jet engine ignition research for conserving industrial boiler fuel. The heavy industrial fuels used in conventional burners, such as pulverized coal, formerly required preliminary ignition of a fuel with a lower ignition point, such as oil. This preliminary burning step is eliminated with the use of the NASA-born industrial ignition system. The use of liquid methane to power vehicles is another adaptation of NASA research.

Although a great deal of technology transfer has occurred from NASA's space discoveries and been used to benefit life on Earth, the amount of direct synergism between NASA's terrestrial and space energy programs is limited by several factors. One is that cost is not as large a consideration in space applications as it is in terrestrial developments. Miller notes, "The cost of the fuel cell for space application, while important to us, is secondary to its capabilities, which are unmatched; there are no other competitive power sources in space. We therefore have a different set of criteria for fuel cells in space than for terrestrial application." Mullin adds, "Some of our technical problems occur because the basic industries we deal with are too cost-oriented. Energy systems developed for terrestrial use—and therefore with close attention to keeping costs down—are simply not good enough for use in space." Costs of energy in space have been in the order of $1000/kWh, according to analyses performed in Mullin's office.

Another inhibiting factor in the ability to successfully transfer technology from terrestrial to space use is that there are great differences in the scale of power sources. For example, the cumulative total amount of power that NASA has installed in space to date is only about 100 kW. NASA's quest toward a space station by the early 1990s would require accumulated experience of two and a half decades in one mission. "To the utility industry," says Mullin, "that's like saying, 'Now we're going to build one power plant that's as big as all that have ever been built before.'"

But in spite of occasional synergistic mismatches, many of NASA's discoveries in advanced technologies have had direct impact on Earth-bound concerns, including applications in the electric utility industry. As the nation's space research continues to grow, opportunities should increase for successful spin-offs to terrestrial electric energy systems. ■

This article was written by Ellie Hollander, Washington Office.

Board Approves Funding for AFBC Plant

EPRI, TVA, Duke Power Co., and the state of Kentucky will cosponsor a $220 million AFBC demonstration plant, with construction to begin in 1985.

Funding for a large-scale electric power plant to demonstrate a clean, economic method of burning coal without unwanted emissions was approved at the summer meeting of EPRI's Board of Directors. A joint proposal from the Tennessee Valley Authority (TVA), Duke Power Co., and the state of Kentucky was selected to sponsor construction and operation of the $220 million, 100–200-MW (e) project at a site near Paducah, Kentucky. EPRI's participation will be $75 million.

The commercial-scale plant will be used to demonstrate a technique of burning coal known as atmospheric fluidized-bed combustion (AFBC). The AFBC boiler is an evolutionary improvement in design that offers a number of advantages over existing pulverized-coal-fired boilers. AFBC boilers can meet stringent SO_2 and NO_x emission control requirements set by the federal government without costly auxiliary scrubbers. AFBC boilers also feature reduced fouling and slagging, allowing greater fuel flexibility.

In an AFBC boiler, coal is fed into a limestone bed that is suspended by a flow of air distributed at the bottom of the boiler. This flow causes the coal and limestone particulates to percolate like a liquid, giving rise to the term *fluidized bed*. The limestone reacts with unwanted SO_2 gases released during the coal burning to produce calcium sulfate. This can be drawn off during the combustion process. In addition, because the coal burns at a relatively low temperature, fewer NO_x emissions are produced.

The project approved by the Board is a tenfold scale-up of the 10–20-MW (e) AFBC boilers now in operation or being tested by the industry. Construction will be initiated in 1985, with testing to begin in 1990. Testing will run from three to five years. If successful, commercial operation will follow.

The demonstration plant will be constructed at TVA's Shawnee steam plant, where EPRI and TVA are conducting a four-year, $28.5 million test program with a $68 million, 20-MW (e) pilot-scale AFBC boiler. Experience gained from operating this boiler will be useful in the design and construction of the large-scale AFBC demonstration plant.

"This project is intended to give electric utilities and manufacturers confidence in achieving the advantages of AFBC at the size needed to generate electricity reliably and efficiently," explains EPRI's Kurt Yeager, vice president, Coal Combustion Systems Division. "EPRI's role in the project will focus on the transfer of technical information to the industry and will include joint responsibility for steam generation specifications development, design approval, and boiler shakedown, as well as developing and implementing the test plan."

Economic studies conducted by EPRI indicate that an AFBC power plant would save 5–15% on the cost of generating electricity over existing pulverized-coal-fired boiler designs, while still meeting all environmental requirements. "The whole purpose of this project is to demonstrate the technical and economic basis for confident utility application of AFBC generating technology on competitive and commercial terms," says Yeager. ■

Major Solar-Thermal Test Under Way

A major test program, an important step in the development of solar power plants, is now in progress in Albuquerque, New Mexico. Ten private corporations are joining with EPRI, the federal government, and the Arizona Solar Energy Commission to fund the $5 million project.

The system is the first in the United States to use molten salt rather than water to transfer the heat collected by a central receiver to a storage unit, where it can be used later to make the steam needed to generate electric power. Mounted on a 200-ft (61-m) tower, the receiver will collect its heat energy from a field of 220 heliostats—giant, faceted mirrors that track the sun during the day. When operating, the test system will feed 750 kW of electricity into the Kirtland Air Force Base power distribution grid.

The use of molten salt is a key difference between the research project at Albuquerque and other experimental solar-thermal power plants in operation today. Because salt in the storage tank retains heat for several hours, small clouds are predicted to have little effect on the plant's operation. Power output can be shifted for several hours, if necessary, to accommodate changes in customer demand. Moreover, complex controls are not required to handle changes in sunlight caused by passing clouds.

EPRI and four utilities together are contributing $1.2 million to the cost of the experiment. The Arizona Solar Energy Commission and five private companies are contributing another $1.2 million in funds and in-kind services. The federal government is funding subcontracts totaling $1.8 million. DOE is also providing support in the form of project management and testing services on the existing heliostat field and tower facility at its Central Receiver Test Facility at Sandia National Laboratories, Albuquerque.

Other contributors include Arizona Public Service Co., Pacific Gas and Electric Co., Southern California Edison Co., Public Service Co. of New Mexico, Babcock & Wilcox Co., Black & Veatch Consulting Engineers, Martin Marietta Aerospace Corp., Olin Corp., McDonnell Douglas Astronautics Co., and Foster Wheeler Solar Development Corp. ■

Interim Board Director and Advisory Council Members Named

During its summer meeting in Denver, EPRI's Board of Directors filled a vacancy on the Board, and Chairman A. J. Pfister announced five new appointments to the Advisory Council.

The new director is Paul D. Ziemer, president and chief executive officer of Wisconsin Public Service Corp. of Green Bay. Ziemer replaces Frank W. Griffith, chairman of the board and president of Iowa Public Service Co., who resigned in June 1983. Ziemer will serve as an interim director until the annual meeting of members in 1984. He will also take over Griffith's spot on the Board's Membership and Bylaws committees. Ziemer has been employed by Wisconsin Public Service since 1948 and was named to his present post in 1971.

The following were appointed to the Advisory Council.

Edward F. Burke, chairman of the Rhode Island Public Utilities Commission. Burke was named to the Rhode Island Commission in 1977 and is a past president of the National Association of Regulatory Utility Commissioners. He held a variety of city and state government posts before joining the commission.

Leonard M. Grimes, Jr., president of the California Public Utilities Commission. Grimes assumed his duties with the California PUC in 1979. Prior to that, he held several other positions with the state of California, serving as secretary of the State and Consumer Services Agency and as director of the State Department of General Services.

Daniel A. Poole, president of the Wildlife Management Institute since 1970. He has also served as chairman of both the Natural Resources Council of America and the Citizens Committee on Natural Resources.

Raphael Thelwell, director, economic analysis, of the National Association for the Advancement of Colored People. He has held his present post since 1980. Prior to that, he was an associate professor in the School of Business and Public Administration at Howard University, served as a senior analyst for the U.S. House of Representatives Committee on the Budget, and was employed in the Office of Management and Budget in the Executive Office of the President.

Andrew Varley, chairman of the Iowa State Commerce Commission. Varley joined the commission in 1979. He served as an Iowa state representative for 12 years and was Speaker of the House for 2 years. He is president of Pine View Angus Farms, Inc.

All five appointees will serve on the Advisory Council until June 30, 1987. ■

Energy Reporter Series Covers 12 Topics

Finding up-to-date information for teaching energy topics in today's classroom can be difficult because of the changing status of numerous energy technologies. EPRI has developed a program called the *Energy Reporter* that can help alleviate the problem—an ongoing series of pamphlets for students, each providing current information on an electricity-related energy technology.

The series was developed by educational specialists working with EPRI's scientific staff and has been tested and evaluated by high school teachers. Each *Energy Reporter* topic is available in a set of 35, supplemented by teacher resource material. Nearly 5000 classroom sets are already in use across the country. The following topics are currently available.

- Electricity: Overview of a Versatile Energy
- Electricity From Coal: Still a Reliable Fuel
- Electricity From Nuclear Fusion: The Promise and the Challenge
- Electricity From the Sun: Technology for Solar Power
- Electricity From Wind: New Use of an Old Source
- Electricity From Nuclear Fission: Splitting the Atom
- Electricity From the Earth: Geothermal Energy
- The Electric Vehicle: Technology at the Crossroads
- Electricity From Water: Hydroelectric Power
- Acidic Precipitation: Collecting the Clues
- Transmission and Distribution: Delivering Electricity
- Electricity From Chemistry: The Fuel Cell

The program allows for teaching flexibility because a combination of topics can be used as a unit in an energy studies, social studies, general science, or current affairs class. Or each topic can be integrated separately into a standard high school curriculum: the fuel cell *Reporter* could be used in chemistry class, fusion in a physics class, geothermal in an earth science class, and so on.

The price for each set of 35 *Energy Reporters* and one teacher's guide is $7.50. For sample copies or more information, contact Carole Goldstein, (415) 855-2147. ■

CALENDAR

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

OCTOBER

11–13
Value of Service Reliability to Consumers
St. Louis, Missouri
Contact: Ronald Wyzga (415) 855-2577

12–14
Seminar: Fuel Supply
New Orleans, Louisiana
Contact: Colleen Hyams (415) 855-2620

17–21
Seminar: Fault Tree and Event Tree Analysis
Dallas, Texas
Contact: David Worledge (415) 855-2342

18–20
5th Symposium on Load Forecasting
Boston, Massachusetts
Contact: Joseph Wharton (415) 855-2924

19–21
Workshop: Generator Monitoring and Surveillance
Dallas, Texas
Contact: Dharmendra Sharma (415) 855-2302

26–27
Meeting: 13th Semiannual ARMP Users Group
Palo Alto, California
Contact: Walter Eich (415) 855-2090

31–Nov. 1
Seminar: Cogeneration Modeling
Atlanta, Georgia
Contact: David Hu (415) 855-2420

NOVEMBER

1–4
Symposium: Flue Gas Desulfurization
New Orleans, Louisiana
Contact: Tom Morasky (415) 855-2468

2–3
3d Annual Contractors' Conference on Coal Gasification
Palo Alto, California
Contact: George Quentin (415) 855-2524

2–4
Two-Shift Cycling of Fossil Plants
Chicago, Illinois
Contact: Frank Wong (415) 855-8969

10–11
5th Annual EPRI NDE Information Meeting
Palo Alto, California
Contact: Soung-Nan Liu (415) 855-2480

13–16
1983 National Fuel Cell Seminar
Lake Buena Vista, Florida
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DECEMBER

6–8
Seminar: PCB
Atlanta, Georgia
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R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

REMOVING GASES FROM GEOTHERMAL STEAM

Fluids produced from geothermal reservoirs contain dissolved gases, which flow with the steam when the liquid and vapor fractions are separated. The presence of noncondensable gases in the steam causes a loss in the net power produced from that steam. Two of the gases, carbon dioxide (CO_2) and hydrogen sulfide (H_2S), give the steam and the condensate a corrosive potential; H_2S may present an emission control problem. EPRI has concentrated its efforts on the removal of these noncondensable gases upstream of the power plant and has developed and tested a process for this purpose. This approach is expected to reduce corrosion, improve turbine performance, and simplify H_2S emission control. Preparations are being made for further tests over a wide range of steam conditions.

The geothermal resources being used in commercial power production today are hydrothermal resources: naturally occurring reservoirs of hot water or steam. Noncondensable gases are often associated with these resources, sometimes in large enough quantities to significantly decrease net power production or, in the case of H_2S, to require emission control. The amount and the components of noncondensable gas in geothermal steam vary from one geothermal field to another and between wells within the same geothermal field. Average steam at The Geysers field in northern California has a noncondensable gas content of about 3000 ppm (0.3%) by weight—mostly CO_2 and about 200 ppm H_2S. The H_2S concentration varies from 50 to 600 ppm at The Geysers. Elsewhere, measured H_2S concentrations are as low as 1 ppm at some fields and as high as 1000 ppm at others.

Over 1300 MW (e) of generating capacity has been brought into operation at The Geysers geothermal field. As power development grew to a capacity of several hundred MW (e), H_2S emissions became a significant issue in power plant siting cases. The abatement of H_2S emissions also became a significant factor in plant capital and operating costs. Unlike most geothermal reservoirs, the reservoir at The Geysers produces dry steam rather than hot water or a two-phase mixture of water and steam. However, the issue of H_2S emission control can also arise at geothermal sites where fluid containing the gas is used to produce power in a direct-flash cycle. (In this cycle, steam is produced by lowering the pressure of hot geothermal water and then is expanded in a turbine generator.) Even if H_2S is not present in any significant amount, a high noncondensable gas content causes a decrease in net power production because of the need to remove the gases from the condenser.

The methods currently used to control H_2S emissions at The Geysers involve chemical processes downstream of the turbine. EPRI has tested an upstream process that does not require chemical treatment of the main steam or condensate flow streams. This process involves condensing the steam and reboiling the condensate in a heat exchanger. Heat from the condensing steam on the inlet side is transferred to the outlet side to reboil the condensate. A small drop in steam temperature between the two sides of the heat exchanger drives the heat transfer. A large fraction of the noncondensable gases (over 95%) and a small fraction of the steam (typically 5%) are vented from the inlet side. This vent stream can be treated separately (aside from the main steam flow path) to remove and dispose of H_2S gas when abatement is required. The other gases (mostly CO_2) can be vented to the atmosphere.

The process being developed by EPRI can remove over 90% of H_2S and other noncondensable gases, can operate at the temperatures and pressures of steam produced at the wellhead in a geothermal field, and does not require chemical treatment of any main flow stream to or through the power plant. These features make it suitable for operation upstream of a turbine. The upstream removal of H_2S and other noncondensable gases has the following advantages over downstream processes that remove only H_2S.

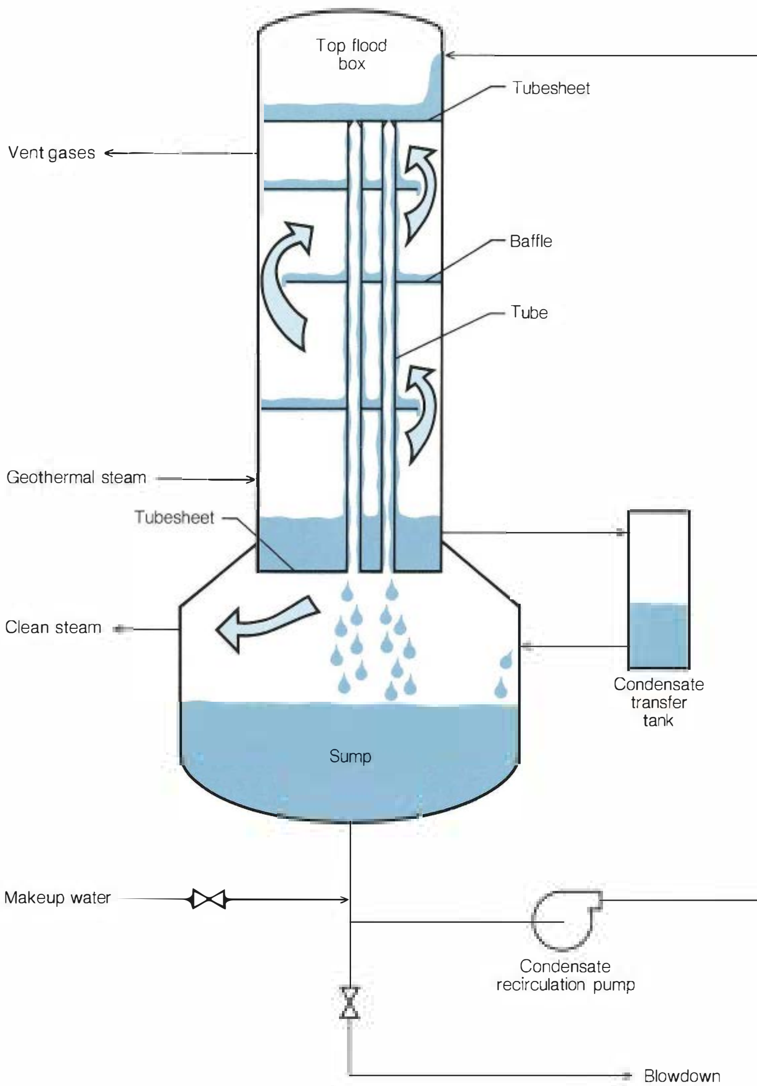
- The steam flowing to the turbine and the condenser is cleaner and less corrosive, which should result in improved reliability.
- H_2S removed by the upstream process does not get into the turbine condensate, where it could require difficult liquid-phase (secondary) treatment to meet plant H_2S emission requirements.
- Because all noncondensable species are removed, the loss of power or steam associated with the ejection of gases from the condenser is minimized.
- H_2S can be removed from the steam even during a turbine generator outage. Thus there is no need to close down geothermal wells or use a separate abatement system to control emissions when the power plant is down.

Process testing

During 1979 and 1980 EPRI tested the upstream process on steam from the main steam line entering Unit 7 of The Geysers power plant, owned and operated by Pacific Gas and Electric Co. Coury and Associates, Inc., performed the field test (RP1197-2), which used a unit designed to handle 0.1 kg/s (900 lb/h) of incoming geothermal steam. PG&E provided support during installation and operation of the test unit.

Figure 1 illustrates the configuration tested. The entering geothermal steam is

Figure 1 Upstream reboiler process for removing noncondensable gases from geothermal steam. This configuration, one of several possible alternatives, features a vertical tube evaporator with the condensing geothermal steam on the shell side and the reboiling condensate on the tube side. In all configurations geothermal steam is condensed and then reboiled upstream of the turbine, and noncondensable gases are removed from the inlet side of the evaporator through a vent stream.



condensed on the shell side of the heat exchanger. Over 95% of the noncondensable gases and a small amount (usually 2–6%) of the uncondensed steam flow out from the top of the shell side in a vent stream. In a commercial unit this vent stream would be treated to remove and dispose of the noncondensable gases. A Stretford plant is one option for such gas treatment. In the field test the vent stream was analyzed to determine its H_2S, CO_2, and ammonia (NH_3) content and was then injected into the cooling-tower basin.

The condensed geothermal steam flows down the outside walls of the heat exchanger tubes to the bottom of the tube bundle and on through the condensate transfer tank to the sump. From the sump, condensate is pumped through the recirculation line to the top of the heat exchanger, where it enters the tube side and flows as a film down the inside walls of the tubes. Steam evaporated from the condensate passes downward through the tubes and exits through the clean steam line.

A temperature difference (ΔT) between the shell side and the tube side of the heat exchanger enables heat to flow from the condensing inlet steam to the evaporating clean steam. Saturated temperature and pressure conditions prevail on each side of the heat exchanger because of an equilibrium between the vapor and the liquid water. In the field test the temperature drop (with a corresponding pressure drop) between the two sides was varied. It was usually kept at 3–6°C (5.5–11°F), although it occasionally ranged to 12°C (22°F). In a commercial unit the ΔT design value would be selected to optimize process economics; that is, the loss of power associated with a larger ΔT and the production of lower-pressure clean steam would be traded off against the increased cost of using the larger-area heat exchanger required for heat transfer at a smaller ΔT.

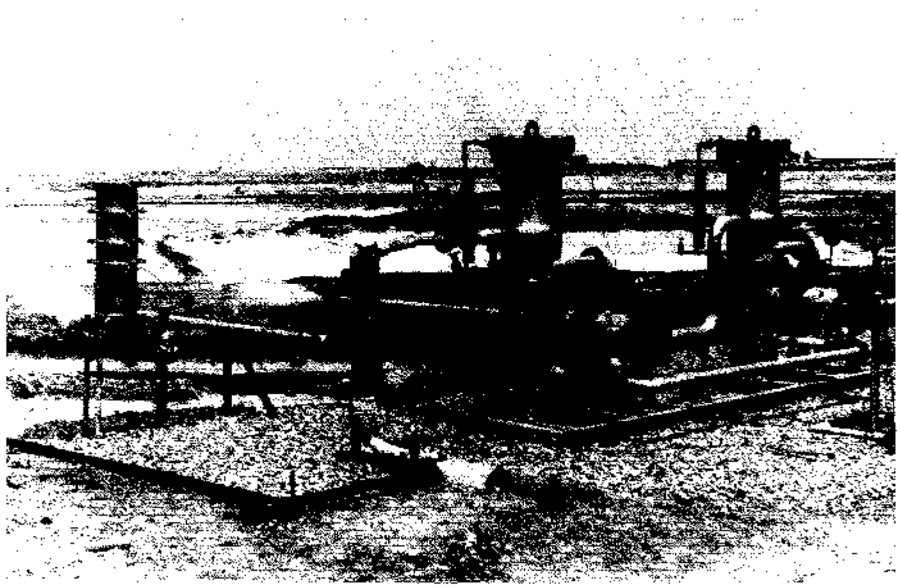
Over 1000 operating hours were logged during the test at The Geysers. H_2S removal was good, averaging 94%; the heat transfer coefficient was adequate, averaging 3400 W/(m² · °C), or 600 Btu/(h · ft² · °F). On the basis of their standard deviation and other considerations, the accuracy of these measurements was estimated to be ±2% for H_2S removal and ±500 W/(m² · °C), or ±90 Btu/(h · ft² · °F), for the heat transfer coefficient.

The average heat transfer coefficient was used to estimate the cost of an upstream reboiler system for H_2S removal in a 55-MW(e) power plant. The costs appeared to be competitive with alternative downstream H_2S abatement systems. The potential cost savings offered by this relatively simple upstream system, which removes CO_2 as well as H_2S, have led EPRI to continue evaluation of the technology.

In cooperation with Mexico's Instituto de Investigaciones Eléctricas (IIE), EPRI is preparing to operate the test unit again, this time using flashed steam at a site with a hot water resource (more common than the dry steam resource found at The Geysers). The reboiler is to be operated over a range of conditions representative of steam that could be produced at a number of hot water geothermal fields. Bechtel Group, Inc., is preparing the test unit and the test plan (RP1197-5). IIE, which will perform the test (RP1197-6), has arranged with Mexico's electric utility, Comisión Federal de Electricidad (CFE), to use fluid from a well at the Cerro Prieto geothermal field near Mexicali, Baja California.

IIE has constructed a steam separator system to supply steam to the reboiler test unit, and CFE has installed the separator system at Cerro Prieto (Figure 2). By using either one or two stages of flashing and separation upstream of the reboiler unit, IIE will be able to supply steam at pressures of 1000, 770, and 400 kPa (approximately 150, 115, and 60 psia) and to vary the concentrations of noncondensable gases in the steam. Injection of CO_2, H_2S, and NH_3 will also be used to obtain different mixtures of noncondensable gases. The test at Cerro Prieto is scheduled for the last quarter of 1983. IIE is sharing the cost of this project, which is one of several cooperative geothermal research efforts planned by EPRI and that institute.

Figure 2 Two-stage steam separation system being tested at the Cerro Prieto geothermal field. This system will supply steam to the EPRI upstream reboiler test unit (not shown) during a field test later this year. Two-phase flow from a well is separated into steam and brine in the first-stage separator (near center). The brine is then flashed again in the second-stage separator (right) to produce steam of lower pressure and lower noncondensable gas content. The reboiler will be tested on both high-pressure and low-pressure steam.



Net power analysis

To determine the effect of an upstream reboiler system on net power output, five factors must be taken into account.

- The decrease in the temperature (and pressure) of steam sent to the turbine due to the ΔT across the reboiler
- The decrease in steam flow to the turbine due to the venting of some steam along with the noncondensable gases in the vent gas stream
- The parasitic power loss or steam loss due to the use of a vacuum pump or a steam ejector to remove noncondensable gases from the condenser
- The savings of power or steam due to the removal of noncondensable gases upstream and the resulting reduction in gas ejection load at the condenser
- The parasitic power required to run the condensate recirculation pump in the reboiler system

As part of RP1197-2, a net power analysis was performed for a hypothetical plant at The Geysers equipped with an upstream reboiler. For comparison the analysis used a power plant without an H_2S abatement system. In many cases this will not be an alternative, and some power loss will be associated with whatever H_2S abatement system would be used if the upstream reboiler were not. The analysis did take into account one important power loss suffered by other systems: the use of 5% of the incoming steam to drive the steam jet ejector system that removes noncondensable gases from the condenser. When the reboiler is used, the steam in the vent gas stream is more than enough to drive the steam jet ejectors to remove the small amount of noncondensable gas entering the condenser. With these factors taken into account, the net power output of a plant equipped with a reboiler system was estimated to be 3% below that of a plant with no H_2S abatement. The results of the analysis are reported in AP-2100.

Recent work for EPRI by The Ben Holt Co. (RP1673-2) has estimated the optimal vent rate for maximizing net power output when the upstream reboiler is applied to direct-flash power systems operating on hot water geothermal resources. The vent rate is the fraction of total inlet steam flow that is vented with the noncondensables and not sent to the turbine. Because a high noncondensable gas content leads to a high partial pressure of gases other than steam, the temperature (and partial pressure) of the steam condensing near the vent gas exit will be lower than if the inlet steam had a low noncondensable gas content. This results in lower-temperature clean steam and, hence, lower output power. When noncondensables are about 0.5% of the inlet geothermal steam, the optimal vent rate would be 2%. For inlet steam that is 3% noncondensable gas (assumed to be CO_2), the optimal vent rate would be 5%. For the highest gas content analyzed in the EPRI study, 10% of the inlet flow, the optimal vent rate would be 8%.

The analysis showed a rather broad optimum in all cases; that is, the net power output remains about the same for a range of vent rates. This means that the vent rate can be designed to be somewhat above the optimal net power point in order to maximize H_2S removal. The dependence of H_2S removal on vent rate will be confirmed during the field test program at Cerro Prieto. *Project Manager: Evan Hughes*

ROOT CAUSE ANALYSIS OF COMBINED-CYCLE PLANT OUTAGES

This report describes a data base system developed for analyzing the root causes of failures and unplanned outages in combined-cycle power plants and related equipment. Data collection, processing, and analysis efforts began in January 1982 and are continuing under RP990-7 with Arinc Research Corp. Raw data in the form of work orders and outage reports are being provided by 13 utility plants on a monthly basis. The data encompass both scheduled and unscheduled maintenance activities for all plant equipment. The primary objectives of RP990-7 are to evaluate combined-cycle plant maintenance records to determine root causes of equipment failures; to identify key areas for reliability, availability, and maintainability (RAM) improvement; and to develop an automated RAM data processing system for feedback to the project participants.

Under an earlier EPRI contract, Arinc Research performed reliability and availability assessments of seven combined-cycle power plants. A primary objective of these assessments was to explore the feasibility of applying RAM analysis techniques to power plant availability prediction. Appropriate analytic models of single- and multishaft combined-cycle unit designs were developed. RAM analyses using plant outage records demonstrated that accurate availability predictions could be achieved. Further, it was shown that component reliability and maintainability could be related to plant availability by using these models. The results of this study are presented in AP-2536.

Although plant outage records proved adequate to support RAM analyses, it was concluded that more meaningful results could be achieved if the root causes of plant equipment failures and forced outages could be identified at lower levels of components and equipment. Under RP990-7 EPRI asked Arinc Research to analyze plant maintenance records and to formulate the requirements of a system for processing RAM data for plant participants and for contractors involved in EPRI's high-reliability gas turbine development project (RP1187). The data system, called ERAS (EPRI reliability assessment system), will also be helpful to EPRI staff in selecting research projects to improve power plant equipment reliability and availability.

Data base development

In the ERAS project, data are being collected for analysis to determine failure rates and mean downtimes of critical equipment used in combined-cycle plants. The data will be further analyzed to determine equipment reliability and maintainability trends and their effect on plant reliability and availability. Because of differences in plant design, operation, and maintenance policies, an understanding of equipment criticality requires that data be collected for all equipment for the following types of maintenance: unscheduled maintenance, scheduled maintenance whose nonperformance could cause a forced outage, vendor maintenance, and maintenance entailed by an equipment failure, whether or not the failure results in an outage.

Outage reports do not fully document plant equipment failures. In many cases maintenance to repair a failure is noncurtailing either because the maintenance is performed concurrently with an outage or because, as a result of plant design, the failure has no effect on plant output. Although noncurtailing maintenance events may not be as critical as outage-related maintenance events, they represent an important ERAS data requirement for these reasons.

- Noncurtailing equipment failures impose demands on maintenance crews and schedules.

- Data on noncurtailing events are useful in establishing failure rates, root causes, repair man-hours, and parts usage for similar equipment in design critical service.

- The data help engineers establish preventive maintenance procedures and analyze the effectiveness of preventive maintenance in improving equipment reliability.

Because most noncurtailing maintenance events are not formally reported to manufacturers, the ERAS data are being provided to the companies for internal use.

A major weakness of existing utility industry data processing systems is that they have insufficient technical detail to establish equipment failure causes at component or piece-part levels. One objective of the ERAS project is to evaluate whether plant work orders and other records can serve root cause determination efforts.

Table 1 summarizes the ERAS data requirements. The system is intended to document plant equipment failures involving planned outages, unplanned outages, and noncurtailing maintenance. Planned maintenance, whether outage-causing or noncurtailing, is also an important data requirement because such maintenance is often performed to prevent unplanned outages. Valuable information on parts usage and material condition can also be obtained.

Maintenance data are mailed directly from a plant to Arinc Research on a monthly or weekly basis. Arinc sends copies of work orders and outage reports to manufacturers and EPRI project personnel for coordination and feedback. A technical liaison has been designated at each participating utility plant. After work orders have been reviewed, these personnel are consulted as necessary to clarify questions about the specific equipment involved in maintenance, about failure causes, and about work performed during combustion turbine overhauls that may not be reported. The final corrected data are compiled, and each utility is sent a copy of its own data on a bimonthly basis.

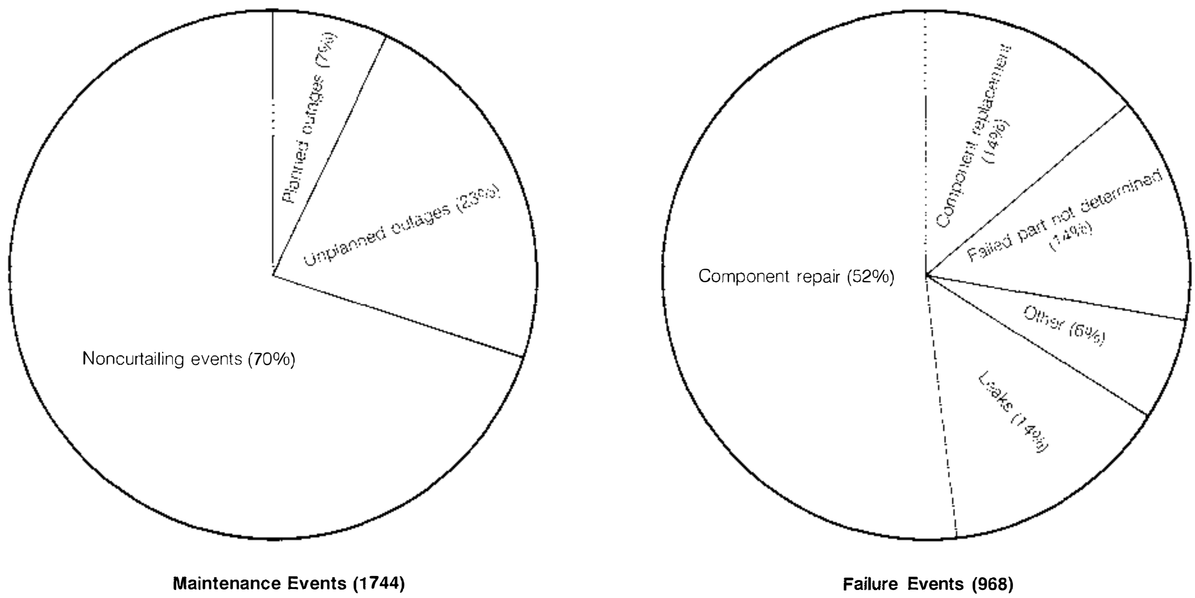
Data analysis and initial findings

ERAS is foremost a repository of raw data records that address combined-cycle plant equipment maintenance activities, both scheduled and unscheduled. The system uses d'BASE II software to organize the data for RAM analysis and for reporting. This software enables the data files to be analyzed in many ways. For example, RAM statistics can be analyzed according to plant design, system, subsystem, or component. ERAS reports can present individual plant data or

Table 1
ERAS DATA REQUIREMENTS

	Data Sources		
Data Requirements	Work Orders	Outage Reports	Personnel Contact
Planned and unplanned outage events			
Failures causing forced outages	×	×	×
Equipment preventive maintenance	×	×	
Parts replacement	×		
Concurrent maintenance	×		
False trips and operator errors		×	
Noncurtailing maintenance events			
Equipment failures	×		×
Equipment preventive maintenance	×		
Parts replacement	×		
Equipment modification	×		×
Root causes of failures and outages	×		×

Figure 3 Total equipment maintenance and failure events for 13 plants in 1982 as documented in ERAS, a data collection and processing system being developed for the analysis of failures and outages in combined-cycle power plants.



combined data for plants of the same design or manufacturer. Users can receive historical plant availability information and analyses of equipment RAM trends, as well as historical maintenance information that may be useful in troubleshooting problems, forecasting man-hour requirements, and estimating parts usage. Special report forms can be developed to accommodate specific data processing needs.

During 1982 a total of 1744 maintenance records for the 13 participating plants were processed. As shown in Figure 3, 70% of the maintenance events did not curtail plant output; 612 noncurtailing events involved component failure.

The ERAS data base for 1982 documents 968 failure events involving more than 200 different combined-cycle plant components. Figure 3 also shows a breakdown of these data. Over 50% of the failure events entailed component repair. Detailed descriptions of the events identifying the causes and the failed piece-parts can be generated, and failures can be grouped by component or by plant.

Power plant work orders appear to be the best available source for data relating to equipment failures, repairs, troubleshooting, engineering modifications, and preventive maintenance. Work orders are particularly useful for identifying failed equipment and piece-parts, replaced or repaired parts, and man-hours spent in repair. (To determine parts usage, however, it may be necessary in some cases to amplify work order information by supplying details on the disposal of a failed part.) When related to equipment operating hours, the work order information enables the determination of equipment failure rates and downtimes.

It has been concluded that work orders do provide insight into possible root causes and can be helpful in failure follow-up investigations, although discussions with plant personnel are often required to supplement work order information. The success of the ERAS data base in determining root causes is difficult to quantify because of different root cause interpretations. However, project efforts have successfully identified the failed piece-part in 86% of equipment failures.

An analysis of plant reliability problems has concluded that failures involving panel controls and remote sensing equipment for combustion turbines and heat recovery boilers are the most frequent cause of combined-cycle plant unavailability. Problems were observed in drum level set points, control valves, panel cards and timers, computers and data links, flame scanners, and thermocouples. The root causes of control system failures are not well documented or understood. However, for many of the control-related problems documented in ERAS, the failed part of the affected control circuit is identified by number. It is expected that as more control system failures are documented and cause and effect relationships are established, these records will begin to yield better insight into root causes.

The microcomputer systems and the d'BASE II data management software used in ERAS have proved effective for organizing and analyzing plant maintenance data. (A remote terminal at EPRI is linked to the Arinc Research terminal, and the network can be readily expanded to include other ERAS participants.) In the first year of ERAS data collection and processing, the following benefits have been demonstrated: better insight into all power plant maintenance, both scheduled and unscheduled; the identification of significant equipment reliability problems that are affecting plant reliability and availability; and the identification of piece-part failures and parts usage at a more detailed level than currently documented in public data sources. *Project Manager: Richard Duncan*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

FLY ASH COLLECTION WITH ESPs

Since 1975 EPRI has supported major research to improve the reliability and efficiency of electrostatic precipitators (ESPs) and to reduce their capital and operating costs. Electric utilities have used ESPs for more than 50 years to collect particulate matter from coal-fired power plants. More than 1500 ESPs are now in use in the United States. EPRI's ESP work has focused on units that collect particulate matter produced by low-sulfur coals. On combustion, low-sulfur coals produce a high-resistivity ash that is difficult to collect and that diminishes ESP performance.

Basic ESP studies

ESP investigators commonly use the Deutsch model to describe precipitator processes and to calculate their efficiencies. As part of its fundamental work on ESP operation and development, Stanford University has examined the standard Deutsch model and postulated a new model designed to overcome its limitations (RP533-1). Predictions of collection efficiencies are often expressed in terms of their effective migration velocity, a parameter determined by collection efficiency and the Deutsch model. In practice, however, effective migration velocity is often significantly smaller than its predicted value. This observation has led to the contention that the Deutsch efficiency is the theoretical maximum for precipitator performance.

This contention is now being challenged by bench-scale data that show both effective migration velocities and measured particle-size dependent collection efficiencies of actual operating ESPs can be substantially higher than those computed for them by using the Deutsch model. Moreover, predictions of other aspects of precipitator performance calculated by using the Deutsch model (e.g., the measured dependence of effective migration velocity on precipitator gas velocity and plate-to-plate spacing) have not proved accurate in practice.

These inconsistencies support the view that the Deutsch model is incomplete. In addition, they suggest that development of a more accurate theoretical description of the precipitation process might lead to better performance predictions and new methods for improving ESP efficiencies above the Deutsch value.

The new model

Unlike the Deutsch model, which assumes that the intensity of turbulent mixing inside the precipitator is sufficiently high to create a uniform transverse particle concentration profile between collector plates, Stanford's new model allows an arbitrary level of turbulence that creates nonuniform transverse particle concentration profiles. This alternative model predicts that precipitators can achieve greater efficiency than the Deutsch predictions with reduction of their turbulent gas flows to approximate fully developed turbulent channel flows. Two laboratory experiments have tested this prediction: one to reduce baffle-induced turbulence at the collecting electrode, the other to reduce corona-induced turbulence.

The baffle-induced turbulence tests used a bench-scale parallel plate collector with variable plate-to-plate spacing to collect precharged particles. This configuration, which corresponds to the collector stage of a two-stage precipitator, conforms as closely as possible to the theoretical model. Measured results showed that the baffles indeed greatly increased the turbulence level in the ESP, subsequently reducing ESP collection efficiency. Introduction of baffles on the collecting electrodes increased the diffusivity in the 45-cm-long ESP from 0.6 to 30 cm^2/s, and the collection efficiency decreased from 94 to 80%. The Deutsch model in the same case (infinite diffusivity, flat profiles) would yield 59% efficiency.

Corona-induced turbulence tests used a single-stage wire-plate precipitator. This configuration produces a corona discharge, which creates a corona wind that interacts with gas flow inside the ESP and causes both turbulent and secondary gas flow. To determine the effect of this turbulence on performance and to test the scaling laws of this effect, values were determined by using the new model and then compared with actual measurements. Both the model and the laboratory measurements showed that corona-induced turbulence can negatively affect precipitator performance. This can be controlled by incorporating various aerodynamic features that maintain the level of corona-induced turbulence below that of background aerodynamic turbulence. This relationship is practical for gas velocities greater than 1.5 m/s, a value typical of modern high-efficiency precipitators.

Two conditions are necessary if commercial precipitators are to duplicate laboratory performance. First, nonideal processes, such as reentrainment, sneakage, back corona, and so on, must not dominate precipitator performance. Second, given satisfaction of this first condition, cost-effective design and construction of precipitators incorporating aerodynamic features capable of achieving small diffusivity values must be within reach. The large increase in turbulence created by baffles on collecting plates suggests the desirability of eliminating or maximizing collecting plate stiffeners, columns, and braces. The next step will be to conduct tests at the 1-MW pilot ESP unit at EPRI's Arapahoe Test Facility in Denver to scale up the laboratory results to more-typical utility operating conditions.

Flue gas conditioning tests

Southern Research Institute has conducted flue gas conditioning tests under RP724-2. The project has two primary goals: to determine the effects of chemical conditioning agents on precipitator performance, and to determine how these chemical agents alter fly ash properties and, consequently, influence performance.

The tests took place at five full-scale utility installations that ranged in size from 180 to 616 MW; in three units, the precipitator was on the cold side of the air heater, and in two units, on the hot side. The precipitator specific collection areas ranged from 145 to 500 ft²/(1000 ft³/min), [28.5 to 98.4 m²/(m³/s)]. The tests used an ammonium sulfate conditioning agent for two of the cold-side units and sulfur trioxide for the third. Both hot-side units used sodium sulfate. All test units burned low-sulfur coal.

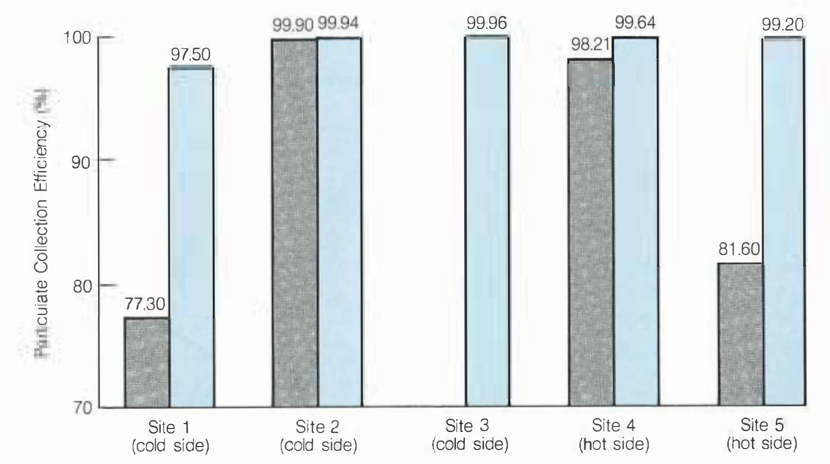
At four of the sites, tests were conducted with and without conditioning, and in every case, the use of conditioning did improve precipitator performance. The degree of improvement varied significantly, as shown in Figure 1. For example, at Site 1 the collection efficiency improved from 77.3 to 97.5%, whereas at Site 2, the efficiency improved from 99.9 to 99.94%.

The major effect of the conditioning agents at all five sites was to reduce fly ash resistivity. Shaded areas in Figure 2 show the range of in situ resistivity measurements during baseline conditioning agent tests for Site 2. These data indicate that the agent reduced resistivity by approximately one order of magnitude.

Subsequent laboratory analysis determined the resistivity of fly ash test samples over a wide range of temperatures and SO_3 concentrations that simulated flue gas conditioning. The result was a classic bell-shaped resistivity-temperature curve consistent with field measurements. Field measurements also indicate that the reduced resistivity stems from the presence of a small amount of SO_3 in the flue gas. In the case of Site 2 (Figure 2) the SO_3 resulted from the partial decomposition of ammonium sulfate after injection in the duct ahead of the precipitator at over 350°F (177°C). Studies to measure the effect of the conditioning agents on other mechanisms affecting precipitator performance—including fly ash agglomeration, fly ash particle cohesiveness, and flue gas space charge—yielded negative results.

Tests to determine how sodium compounds affect hot-side precipitator performance confirmed that sodium ions are the principal charge carriers in fly ash at hot-side temperatures and that sodium depletion, a relatively new concept, was responsible for some major operating difficulties. In a hot-side precipitator operating under sodium depletion conditions, sodium ions in the fly ash layer that builds on collection plates migrate away from the plate, leaving

Figure 1 Precipitator performance data. The color bars reflect data with conditioning; the gray bars, without conditioning. No test data are available for Site 3 without conditioning; however, without conditioning, opacity is 20% at 80% of full boiler load; with conditioning, 2–5%.



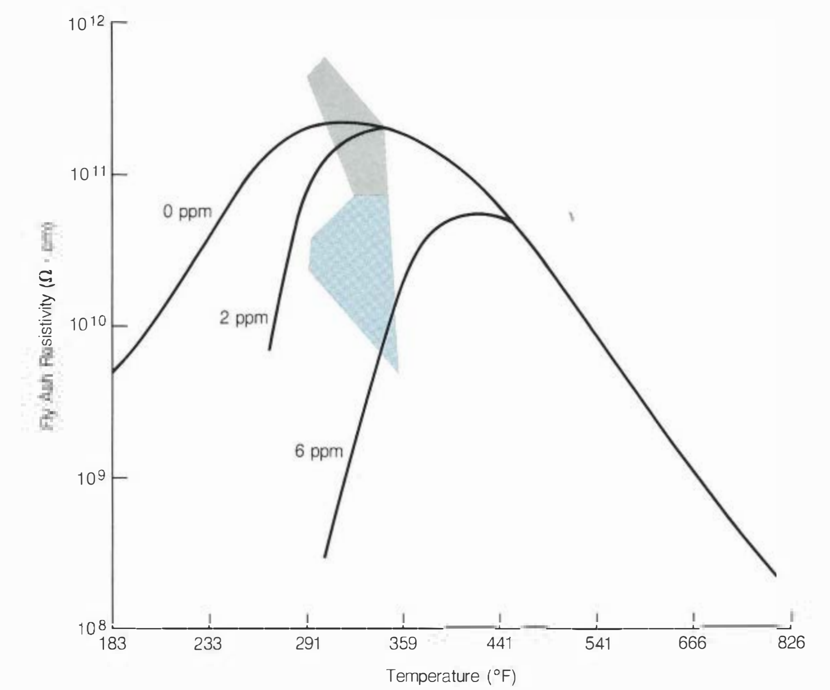


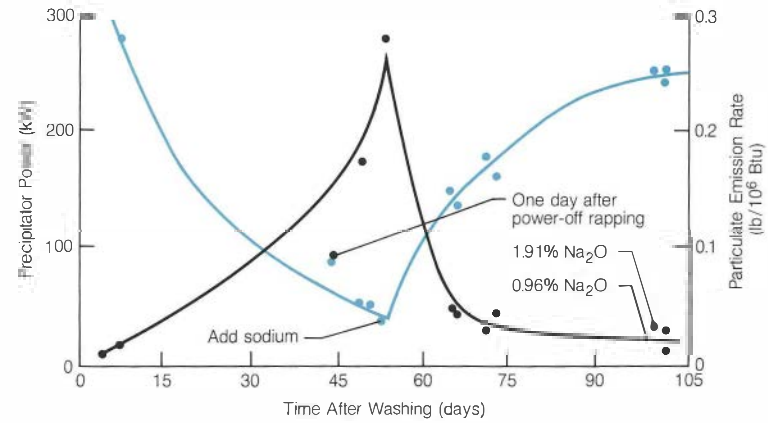
Figure 2 Field and laboratory resistivity values for conditioning tests at several values of SO_3. The gray area represents field results without conditioning (1–2 ppm SO_3 in flue gas); the color area represents field results with conditioning (2–5 ppm SO_3 total in flue gas). The curves represent laboratory data at 0, 2, and 6 ppm SO_3, respectively.

behind a thin layer of ash with very high resistivity. Rapping to remove this thin layer has proved impractical. Thus, ash resistivity continues to increase over time, thereby reducing precipitator performance.

Figure 3 illustrates the effect of sodium depletion and sodium conditioning on one hot-side precipitator. At the beginning of the test, the precipitator entered service with clean plates (the plates were washed during a unit outage). The newly precipitated fly ash layer had low resistivity, power levels in the precipitator were high, and collection efficiency was high (99.88%). However, after a little more than 50 days of operation, increasing fly ash resistivity had decreased precipitator performance to an unacceptable level, and sodium was added to the coal supply to moderate the sodium depletion in fly ash on the plates (through back diffusion of sodium ions from the newly precipitated sodium-rich layer into the sodium-depleted layer). When the sodium content of the fly ash reached 1.91%, power levels increased and outlet emissions dropped to an acceptable level, again within about 50 days.

Data gathered during all of the field tests and laboratory studies, together with existing knowledge of precipitator operating characteristics, now make it possible to generalize results to other sites. A flue gas conditioning user's manual, now in preparation, will outline a procedure for evaluating the performance of existing precipitators and for estimating the effect of gas conditioning on performance. The first edition, scheduled for publication later this year, will focus primarily on the use of sulfur compounds for cold-side precipitator applications. Subsequent editions will assess the effects of other chemical agents on hot-side precipitators. *Project Managers: Walter Piulle and Ralph Altman*

Figure 3 The effects of sodium depletion on precipitator performance over time. The color curve and data points indicate measured power consumption; the black curve and data points indicate emission measurements.



STEAM TURBINE BLADING

Steam turbine generator availability and performance have declined in recent decades, at least partly because of relatively rapid increases in unit sizes and greater operating temperatures and pressures. To accommodate these changes, utilities have had to introduce new materials and more complex equipment at a pace and scale that allowed unanticipated problems to develop in many large units. With greater nuclear capacity and more-efficient fuel plants to provide baseload power, many large turbine generators originally designed for this purpose now perform only cycling or peaking duty. These changes have resulted in more difficult operating conditions for these plants and recurrent operating problems with components, particularly steam turbine blading. To increase the industry's understanding of blade failures, EPRI recently surveyed 125 utilities that operate 494 units of 300 MW or larger (RP1856-1). These utilities reported that replacement power alone cost $1.4 billion between 1970 and 1981.

Low-pressure turbine blading

Failures in low-pressure (LP) turbines account for 75% of all reported blade failures, three-fourths of which occur in the last (L − 0) and next-to-last (L − 1) rows. These failures generally result from a corrosive medium, susceptible materials, and/or stress (primarily fatigue stress), acting either individually or in concert.

As steam expands through the turbine, contaminants in the steam-water cycle concentrate and precipitate to create a corrosive medium. This effect is most pronounced as dry steam becomes wet steam, a transition commonly called the Wilson point. EPRI is investigating the effects of such contaminants as chlorides, silicas, and oxygen, that can reduce the fatigue strength of typical turbine blading materials to as little as 20% of their value in air. This work will provide the data necessary for utilities and manufacturers to improve the design and operation of steam turbine blading.

EPRI investigated the corrosion fatigue characteristics of several blading alloys—including type-403 stainless steel, 17-4PH stainless steel, and Ti-6A1-4V titanium alloy—in chloride-containing corrosive environments (RP912). The Ti-6A1-4V alloy most effectively resisted corrosion effects, losing only 20% of the fatigue strength it had shown in pure-water tests. The 17-4PH alloy was the next most effective, followed by type-403 stainless steel. Other EPRI projects have determined the quantities and locations of contaminants in operating steam plants. Southern California Edison Co. (SCE), using a Dionex ion chromatograph, identified contaminated condensate polisher chemicals as the source of chloride contamination in its Redondo and Alamitos plants (RP1408-3).

In investigating susceptible materials as a second source of blade failure, EPRI and others have undertaken metallurgical research to quantify the effects of material properties on stress corrosion cracking (SCC). Because higher-strength materials are generally more prone to SCC, use of a stronger material for turbine blades may not be a practical response. Thus, EPRI, along with host utilities and turbine manufacturers, is investigating alternative materials.

For example, EPRI has been working with Westinghouse Electric Corp. to develop and qualify a titanium alloy suitable for low-pressure steam turbine blading (RP1264). Titanium's relative invulnerablility to environmental attack makes it an ideal material for this application. Successful laboratory work has led to the manufacture of a row of Ti-6A1-4V blades, which project personnel will install at Commonwealth Edison Co.'s Kincaid station in the spring of 1984. An identical free-standing row of 17-4PH steel blades will provide a reliable comparison for the demonstration test.

Another approach is to apply protective coatings to turbine blades as a barrier to corrosion (RP1408-1). SCE and Westinghouse have installed blades with experimental coatings in a low-pressure turbine at the Redondo-7 unit. The test will investigate Teflon, nickel-cadmium, and ion-vapor-deposition aluminum coatings to determine their potential for low-cost protection of turbine blades from SCC-induced fractures.

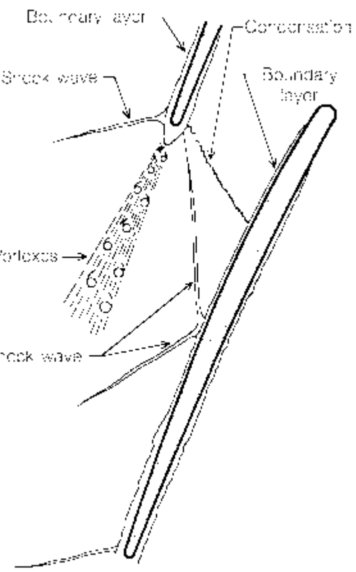
Stress is a third major source of turbine blade failures. The flow of steam over turbine blades subjects them to synchronous and nonsynchronous forces that impose alternating stresses on the blade material; moreover, these stresses combine with the static centrifugal stresses caused by rotation. Interactions between boundary layers and shock waves can superimpose unstable forces on blade-passing impulses from the stationary blading. Effective design of turbine blades depends on careful analysis of this complex set of forces, the resulting fatigue-causing vibrations, and the stresses in blades.

Westinghouse is investigating the interactions of condensation, shock waves, and boundary layers on the transonic flow in low-pressure steam turbine blading (RP1407). Laboratory investigations verified the existence of these phenomena (Figure 4), and in 1980 Westinghouse and Pacific Power & Light Co. applied the findings in a field test at PP&L's Centralia plant. The laboratory data helped investigators develop turbine operating guidelines to prevent recurrence of condensation–shock wave phenomena.

Stress Technology, Inc., is developing an interactive computer code for independent analysis and evaluation of blade designs (RP1856-2). The code, called BLADE (blade life algorithm for dynamic evaluation), uses finite element analysis to determine the root cause of a blade failure, evaluate alternative designs, and develop improved operating and procurement guidelines for steam turbine blading.

These and other efforts will eventually become part of an overall program to assess, predict, and improve the operating life of turbine blades. The program will also develop a noncontacting method of determining actual operating stresses for use with data on materials and blade performance. With this information, investigators will attempt to determine the probable life of proposed blade designs, assess expended and remaining life of existing blades, and establish operating guidelines for extending blade life.

Figure 4 The interaction of condensation and shock waves in L – I blades in low-pressure turbines. The interaction of spontaneous steam condensation, transonic shock waves, and blade surface boundary layers can produce unstable nonsynchronous vibrations in low-pressure steam turbine passages.



Solid-particle erosion

The erosion of steam path surfaces in the blading, nozzle blocks, control valves, and other components of high- and intermediate-pressure turbines is one cause of diminished plant performance. Investigators generally agree that the source of this erosion is exfoliation of hard particles of iron oxides from superheater tubes, reheater tubes, steam headers, and steam leads during operation—principally during startup or abrupt load changes.

ASME surveyed a group of utilities in 1978 to determine the magnitude of the problem. The results confirm that solid-particle erosion (SPE) damage is widespread, causing increased maintenance costs and lost efficiency. Preliminary findings indicate that the average annualized cost of these SPE-induced problems is about $0.70/kW of capacity, or $420,000 annually for a 600-MW plant.

EPRI is actively investigating the following three strategic alternatives to minimize the effects of SPE.

- Eliminate exfoliation by using special materials, treating tubing and steam system surfaces, or avoiding abrupt load changes (e.g., through sliding pressure)
- Strengthen vulnerable components by using erosion-resistant materials for blading, nozzles, and valves; applying special coatings; or adding inserts to particle-attack locations
- Remove particles from the steam path through steam bypass systems during startup or rapid load changes or through particle-removal traps

EPRI research has shown that exfoliation results principally from differential thermal expansion of tubing scale and its substrate. Foster Wheeler Development Corp. developed an aqueous chromating treatment that reduces scale formation and exfoliation and is suitable for application to existing boiler components (RP644-1). Following successful tests on selected superheater and reheater tubes in several plants, EPRI recently sponsored a full-scale chromate treatment at the Glenwood station of Long Island Lighting Co. of New York. Project personnel will monitor these retrofit applications for several years to determine their effects on the long-term performance of the treated components.

General Electric Co. is developing a particle monitor to investigate the characteristics of exfoliated particles in operating plants (RP1885). This work is essential to the development of viable, cost-effective options for reducing SPE. A second part of the project will develop and test improved erosion-resistant coatings for turbine blades and nozzles. Power Dynamics, Inc., is evaluating the use of steam-bypass systems to bypass exfoliated particles during startups or to minimize boiler temperature transients that accelerate SPE (RP1879).

Application of results

Given the wide range of operating environments, materials, and designs, no single solution is likely to resolve all blade-related problems in high- and low-pressure steam turbines. Technology options adaptable to the needs of individual utilities and operating units are necessary, as is an integrated analysis that considers the effects of the operating environment, blade and boiler materials, and fatigue stresses on blade reliability and performance. Turbine and boiler manufacturers' R&D in specific technologies complement EPRI's work to catalyze the development of optimal blading solutions. *Project Managers: Thomas McCloskey and Isidro Diaz-Tous*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

OVERHEAD TRANSMISSION

Lightning performance of transmission lines

John G. Anderson of General Electric Co., author of the lightning chapter in EPRI's red book (*Transmission Line Reference Book, 345 kV and Above*), has devised an improved method for calculating the lightning performance of transmission lines (RP2080). Using a computer program, MULTI–FLASH, the transmission line designer can more accurately predict the lightning flashover performance of single and multiple circuit transmission lines. The program will handle up to 12 ac phases, 12 dc poles, or any combination thereof on the same transmission tower with a variety of tower shapes and insulator strengths.

The analysis starts with the classical method used in the EPRI red book, but it incorporates a new method of describing tower members, so nonconventional designs can be handled as easily as conventional ones. All transmission voltage and significant corona effects are included, as well as the statistical distribution of footing resistance. The output includes an analysis of expected shielding failure performance, followed by a detailed tabulation of the expected flashover frequencies of each of the phases or dc poles that are involved. This output has been successfully verified by field data from several TVA transmission lines.

A principal feature of MULTI–FLASH is its ability to analyze the lightning performance of multicircuit structures. This is important for the transmission line engineer because on most double-circuit lines, when one circuit flashes over, the second circuit will simultaneously flash over 40–60% of the time. If this is unacceptable for a specific system, alternative designs or materials to reduce the double-circuit flashovers should be investigated. Using MULTI–FLASH, the designer can explore new and innovative shapes or materials and accurately predict the degree of improvement achieved.

This computer program is currently being used by several utilities to make sure that the user's manual is complete and understandable. MULTI–FLASH will be ready for distribution in the spring of 1984. Engineers needing this program before then should contact the project manager. *Project Manager: John Dunlap*

Induced ac potential on pipelines

A four-volume final report and a computer program are available to predict voltages and currents induced on parallel piplines by electric transmission lines (EL-3106, Vols. 1–4). These results from a two-year research project, cosponsored by EPRI and the American Gas Association (AGA), provide ways to analyze complex joint right-of-way occupancy conditions consisting of multiple power lines, multiple gas pipelines, electrical bonds between the pipelines, pipeline terminations, and insulating joints in the pipeline (RP742-2).

- Volume 1 details the development of the analytic methods and describes data from field tests used to verify the accuracy of the results.
- Volume 2 is a handbook containing graphic solutions convenient for field personnel or others not having access to a computer.
- Volume 3 is a user's guide for the computer program PIPELINE, with examples of its use.
- Volume 4 contains details on a new method of mitigating induced voltage on pipelines by coupling them with a conductor buried in parallel.

Designers will find the computer program PIPELINE very helpful in calculating the voltages and currents induced on parallel pipelines. Utilities using the program during the development period found it to be versatile, comprehensive, and, equally important, easy to use. For those not having access to a computer or wanting to make a quick first approximation, the handbook provides graphic solutions to typical power line/pipeline problems.

A new method to reduce the induced voltage on pipelines in areas of high soil resistivity, such as desert areas, has been developed and field demonstrated.

The report and the computer program PIPELINE are valuable aids for power line and pipeline designers whenever parallel operation of these facilities occurs or is planned. This project is a good example of how cooperative research can produce practical results useful for solving problems on a multi-industry basis. *Project Manager: John Dunlap*

TRANSMISSION SUBSTATIONS

Mitigation of geomagnetic-induced currents

Geomagnetic storms triggered by solar flare (sunspot) activity can induce voltage gradients between different points on the earth's surface. This can cause quasi-dc currents to flow through system grounding points that are remote from each other. Power systems in northern latitudes are most susceptible to these geomagnetic storms. The interconnected systems of Manitoba Hydro, Minnesota Power & Light Co., and Northern States Power Co. are one such example.

Previous research investigated the effect of geomagnetic-induced current (GIC) on the Winnipeg–Duluth–Twin Cities 500-kV transmission line (EL-1949). The research indicated that GIC can cause half-cycle saturation in power, current, and potential transformers. This, in turn, can cause unusual real and reactive power flow, undesirable harmonics, and misoperation of protective relays.

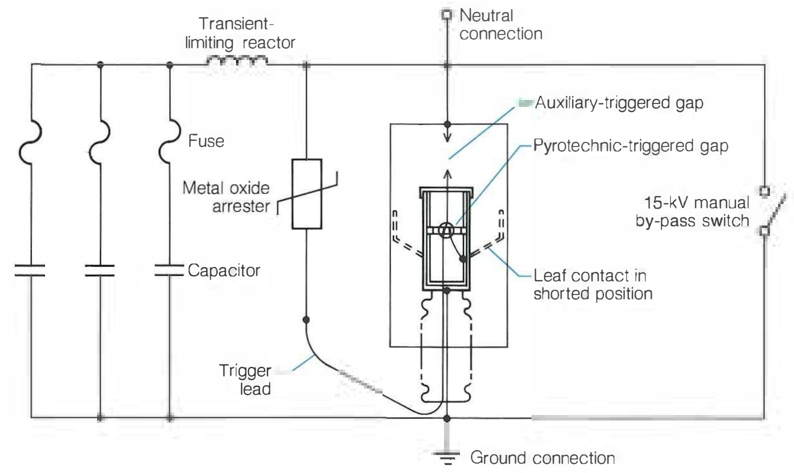
A parallel project was initiated to determine whether GIC would damage power transformers (RP1424-3). This project indicated that although the noise level increases with increased dc current, there was little risk of damage to transformers.

As a result of the earlier work, a follow-on project was initiated to determine the impact of GIC on ac and dc systems and to investigate a means of mitigating these effects (RP1770). This work is now complete, and a final report is in preparation.

Field tests confirmed that saturation of the core and consequent undesirable effects can be caused by GIC and stray dc currents flowing in large power transformers. Modeling techniques and computer programs for determining the GIC flow in the power system network, given the earth surface potentials, were developed. These studies also showed that the effects of GIC and stray dc current in converter transformers of an HVDC system could interfere with normal HVDC operation.

Both active and passive devices were investigated for insertion in the grounded neutral points to mitigate the effects of or to block GIC. The most promising system uses neutral blocking capacitors with a novel protective scheme (Figure 1).

Figure 1 Neutral blocking and grounding device for blocking geomagnetic-induced and stray dc currents. The entire device, including the capacitor bank, is 4 × 2.5 × 5 ft (1.2 × 0.76 × 1.5 m).



In this system, capacitors normally block the flow of dc current from the transformer neutral to ground, while allowing the normal system unbalanced ac current to flow. To minimize capacitor size, a fast-acting, low-cost protective device is required. In the scheme developed, if fault current of sufficient magnitude causes the capacitor voltage to rise to dangerous levels, the standard distribution-type metal oxide arrester will begin to conduct current into the trigger lead of the pyrotechnic-triggered gap (PTG). This will then ignite a chemical charge in the PTG, causing leaf contacts in the PTG to short the entire assembly and permanently connect the transformer neutral to ground. A backup gap (auxiliary-triggered gap) incorporated in the PTG would flash over and ignite the chemical charge should the metal oxide arrester fail to function. The PTG is a one-shot device, which is low in cost and easy to replace. Sample PTGs have been built and tested successfully, demonstrating that PTG conduction time is less than 50 μs after firing. Dielectric, heat run, and other tests for this application were also successful.

System studies of the Manitoba Hydro–Minnesota Power & Light–Northern States Power interconnection were made to determine the best way to apply this scheme. These studies determined the optimal locations on the systems to mitigate GIC and the number of units that would be activated under various fault conditions. Studies were also made to estimate the installed cost of the mitigating devices and the replacement costs of the PTGs. These studies concluded that this mitigating scheme was the most economic of the methods evaluated. Detailed project results will be reported in the final report when it is issued late in 1983. *Project Manager: Joseph Porter*

Fault location system for HVDC transmission lines

The existing fault-locating equipment for HVDC transmission lines seeks to compare the time of arrival of a transient that travels in opposite directions on the faulted line to the two ends. A wideband communications channel is used to transmit the time taken to reach the remote end of the line, so the equipment must always function properly. Such a system typically costs $200,000, excluding the cost of the wideband channel, which is also costly. Even though fault locators are used on both ac and dc lines, their need on the dc lines is especially critical because the dc lines usually are quite long, and to manually patrol the full length of the line is prohibitively expensive.

In early 1982 EPRI started a project with Washington State University to develop a low-cost line fault locator for HVDC lines (RP2150-1). A major goal of this research project is to develop the means to locate faults on the line by using information available at just one end of the line. The approach under study is to find fault-caused stationary voltage minima by analyzing the traveling waves produced by the faults.

The transmission line voltage can be represented by the sum of a forward-traveling wave and a backward-traveling wave. These traveling wave components can be found from voltage and current measurements at any convenient point (e.g., one end of the line). If these components are added together with appropriate time offsets, an estimate of the voltage at any point along the line can be obtained.

To obtain a degree of accuracy useful for fault location requires a complete and precise model of the system. The system model contains three simpler models linked together: a line model, a terminal model, and a fault model.

The system model is implemented in a computer program, and its output is compared with field measurements obtained with a data collection system. The line fault data collection system monitors line voltages and currents and then records a "snapshot" whenever a line fault is detected by the system.

To demonstrate this detection method, Bonneville Power Administration volunteered to be the host utility and try the system on the Pacific DC Intertie. The data collection system has been partially installed at the Celilo station (north end of the intertie) and is currently awaiting an outage to install the two current shunts that will complete the data collection system.

The system accepts five analog inputs, which are proportional to the line voltages (V3, V4), line currents (I3, I4), and neutral bus voltage (VN). Figure 2 shows the interconnection of the data collection system and the voltage and current transducers. The voltage transducers are the existing dividers at Celilo.

Figure 3 diagrams the data collection system. The five analog signals are filtered through low-pass filters, sampled, and converted to binary numbers every 40 µs by the two data acquisition computers. These computers store the samples in circular buffers, providing a 160-ms-long record of the newest samples.

Every millisecond, a voltage sample from each channel is transferred to the main computer, where the samples are digitally filtered to determine if a line voltage disturbance has occurred. If one has, the data acquisition process continues for another 120 ms, then stops. At that point, the data acquisition computer memories contain about 40 ms of predisturbance data and 120 ms of postdisturbance voltage and current data. Next, these data are transferred from the data acquisition computers, through the main computer, and onto a disk.

A printing terminal is provided for system startup, testing, and control. A calendar-clock provides date and time data to the main computer. An annunciator panel monitors the status of two output relays to indicate disk-full or processor-stall conditions. The model output, as well as the field-collected data, will be used to develop and evaluate a fault-locating algorithm based on the traveling-wave analysis described.

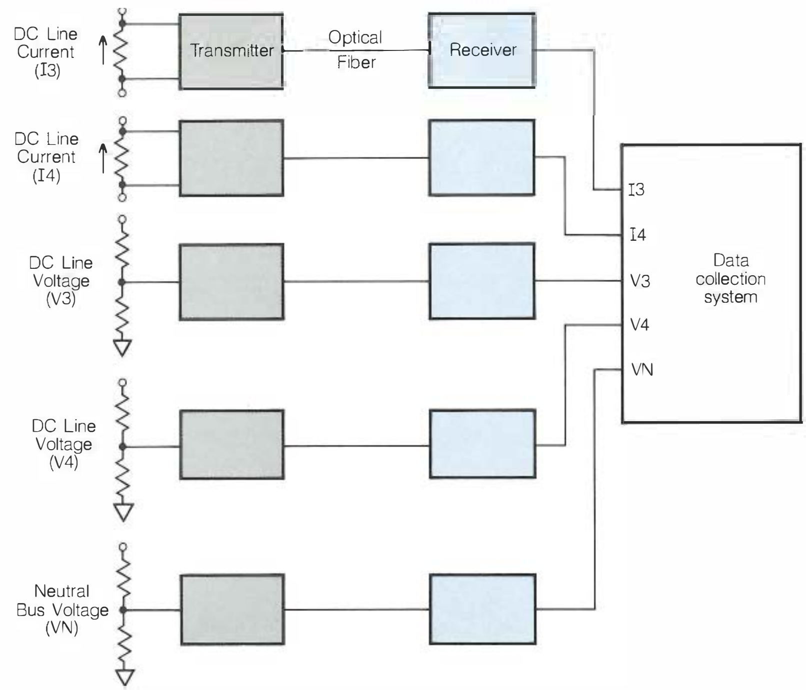
The recorded fault data will be used to verify the performance of dc line-fault-locating algorithms under development at WSU. When the algorithms have been developed and tested, they will be transferred to the data collection system computer so that line fault location will be computed on site. *Project Manager: Vasu Tahiliani*

UNDERGROUND TRANSMISSION

Evaluation of pipe-type cable restraint systems

A significant part of electric power transmission is by underground cables, which are predominantly oil-pressurized, impregnated-paper-insulated cables. Of the 3000 circuit miles of underground transmission in the

Figure 2 Voltage and current signals are fed into the data collection system for fault location on HVDC transmission lines. The gray blocks represent fiber-optics transmitters; the color, fiber-optics receivers.



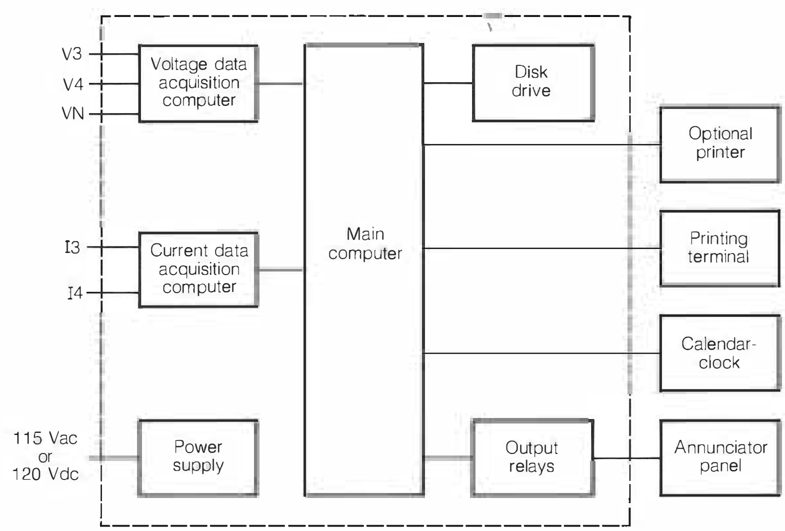


Figure 3 Analog signals received by the data acquisition computers are filtered, sampled, and converted to binary form every 40 µs and stored in 160-ms segments. Every millisecond, a sample from each channel is transferred to the main computer to determine if a line voltage disturbance has occurred.

United States, approximately 85% is by steel-encased, high-pressure, pipe-type cable. Most of the underground circuits are concentrated in metropolitan areas and also serve as indispensable power transfer interconnections between large utilities. For example, the three major utilities in the New York–New Jersey combined metropolitan area have over 2000 circuit miles of underground transmission. Traditionally, the reliability of these underground cable systems has been exemplary: less than 1.5 interruptions per 100 circuit mile–years (161 circuit kilometer–years).

When it recently became apparent that troubles were developing from excessive bending of 345-kV pipe-type cables within the joint casings, a project was funded to study and test restraining devices to protect the cables and prevent future in-service outages (RP7894-1). Public Service Electric and Gas Co. (PSE&G), whose engineers developed a retrofit restraint device, served as subcontractor to Pirelli Cable Corp., which provided project management and specialized test facilities.

Pipe-type cables, manufactured and installed in lengths of 2500–3500 ft (760–1070 m), must be spliced together inside large joint casings within underground manholes. Where the cables and splices are insufficiently supported, repeated sharp bending of the cables from thermal longitudinal expansion can result in permanent damage to the cable insulation, possibly reducing dielectric strength.

To test the restraint devices, full-size 345-kV cables and splices were prepared and installed in the 10-in (255-mm), specially designed 65-ft (20-m) pipe facility at the Pirelli laboratories. Two parts of the modular pipe sections were arranged to slide together, or telescope, so that in effect the cable lengths are longer than the "shortened" pipe and must bend to accommodate the difference.

By actuating the hydraulic system, incremental cyclic thermomechanical expansion effects were simulated in the cables, joint assembly, and restraint devices. The tests were continued, with increasing movement, until some 42,000 cycles, or the equivalent of over 115 years' service, had been accumulated on the assembly without distress. (Figure 4 is a view of one-half of the restraint device around the 345-kV splices, with the outer casing removed.) After prolonged withstand at 8000 lbf (35 kN), the assembly was subjected to tensile tests up to 19,000 lbf (85 kN)—well beyond expected requirements. This test successfully evaluated the restraint device as an anchor against cable movement

Figure 4 Restraining device supporting three 345-kV cable joints (outer case removed).

down inclines along the cable route.

PSE&G installed over 20 of these restraint systems on its Mahwah–South Waldwick and Hudson-Farragut 345-kV pipe-type cables as reinforcing devices to ensure the reliable service performance of these interconnections. *Project Manager: Stephen Kozak*

Morphology of cross-linked polyethylene

Morphological characteristics (nature of single structures) of cross-linked polyethylene (XLPE) cable insulation are being studied at the University of Utah to determine the potential influence of polymer morphology on insulation behavior and cable life (RP7891). Other project goals were summarized in an earlier *EPRI Journal* article (November 1981, page 45).

Polyethylene inherently forms spherulites when processed, and although this is fairly well understood, the morphology of XLPE is less well understood; hence the possibility that morphology influences cable life.

The early phase of this work focused on 138-kV cable specimen preparation, fusion studies, and extraction studies; methods employed included differential thermal analysis, optical microscopy, scanning electron microscopy (SEM), and transmission electron microscopy. The results of this work have led to the preliminary finding that the gel and sol fractions of XLPE insulation appear to crystallize separately during the cooling process that takes place after cross linking; also, that sheafs and partial spherulites occur throughout the entire cross section of cable. When the spherulitic structure of XLPE cable walls was compared with that of molded sheets of the same material and examined by SEM, some differences were observed—the molded sheets exhibited banded spherulites that were larger in diameter; in neither case could Maltese crosses (structural phenomena commonly observed under polarized light) be readily seen. In general, XLPE spherulites are considered too small for good internal resolution, which makes XLPE different from low-density, high-molecular-weight polyethylene in this respect. This work is facilitating our understanding of XLPE insulation structure, an area not attempted in the past. *Project Manager: Bruce Bernstein*

Cable breakdown study

The acquistition of statistically valid breakdown data on HV and EHV underground transmission cables has progressed significantly since the inception of this 4½-year project (RP7879). EPRI and Empire State Electric Energy Research Corp. have cofunded this work with Underground Systems, Inc., as prime contractor. Testing is being done at the Phelps Dodge Cable & Wire Co. EHV laboratory in Yonkers, New York. To date, all work has been on high-pressure oil-filled (HPOF) pipe-type cables, and 49 tests have been completed. Extruded cable testing will be undertaken in the final year of the project.

As a minimum, testing should accomplish the following.

- Establish the variability in breakdown levels of present-day pipe-type cables and obtain a measure of how the levels might vary among cables
- Search for a consistent relationship between impulse breakdown and switching-surge breakdown
- Determine the effect of temperature on impulse and surge breakdown level and check for consistency of the observed relation among samples
- Determine the effect of pressure on impulse, surge, and ac breakdown
- Establish the exponent *n* of the life model

The data that will be generated in achievement of these goals is of prime importance to cable designers, standards writers, and system operators because these data do not exist today.

Performance of breakdown testing appears simple, but in reality it is quite complex. Although ac, impulse, and switching-surge tests are of primary interest, the conditions under which these tests are made have a great deal to do with the usefulness of the resulting data. For example, the temperature, the pressure, whether the cable should be bent or straight, whether it should be preconditioned with ac voltage and for how long are all critical to those ultimately using the information. Because budget constraints do not allow testing under all conceivable conditions, a workshop was held early in this project to arrive at treatment and conditioning measures that would be acceptable to standards-setting groups and others in the industry.

Although the project is specifically oriented toward data collection only, comprehensive analysis and correlation with test conditions will be needed before manufacturers and utilities can make full use of the results. *Project Manager: John Shimshock*

ROTATING ELECTRICAL MACHINERY

Prediction of electric machine constants by finite element analysis

The electric utility industry needs accurate models for its major generators in order to predict the performance of the power system in the event of a disturbance. These models, usually in the form of direct- and quadrature-axis-equivalent circuits, are used in transient stability programs that are run on digital computers. Using these programs, power system analysts can study the effect of a given disturbance on different system configurations to see which of them are likely to maintain stable operation following the event. These studies are the basis for decisions on which configurations (e.g., transmission capacity, reserve generation) are tolerable for system security. As such, they have a direct bearing on such areas as system planning, timing of planned maintenance outages, and economic generation scheduling. The ability of a system to survive a major disturbance depends largely on whether or not the large generators can maintain synchronous operation following the transient. For this reason, models that reliably predict the behavior of large generators are crucial to the accuracy of transient stability studies.

Models derived from the industry's standard (IEEE 115) for specifying the performance of synchronous generators are generally considered to be inadequate for large turbogenerators. The standstill frequency response test has been proposed as a method for deriving better circuit models for large generators. However, this test does not completely account for all the effects of saturation and must be performed on an as-built generator. Hence it is of limited application in system planning.

Progress in the development of finite-element analysis techniques to electromagnetic field problems has laid the basis for obtaining more-accurate generator models by analytic means. The objective of two projects is to demonstrate the feasibility of this analytic process (RP1288, RP1513).

The finite-element procedure has capabilities beyond present test procedures, in terms of representing saturation in the generator and permitting the creation of circuit models during the generator design phase. Using these analytic tools increases our understanding of generator performance characteristics and may ultimately improve generator operating characteristics. The objectives of the present projects are the following.

- Develop the appropriate finite-element procedures for obtaining generator models
- Demonstrate the use of the procedures by sample calculation of generator characteristics
- Validate the methods by comparing calculated generator parameters with those obtained by test
- Explore methods for obtaining generator models applicable to large-signal transients

The first two of these objectives were met for both nonlinear steady-state (magnetostatic) analysis and linearized analysis of small perturbations at arbitrary frequency. In particular, studies of a number of finite-element grid configurations showed the capability of representing perturbation signals up to 100 Hz. At frequencies of this magnitude, the skin effect in the rotor iron is pronounced. The limitations of gridding under conditions of pronounced skin effect have been defined, and appropriate procedures for correctly handling this effect have been demonstrated.

The third objective was also satisfactorily met. The validation of both the steady-state and small-signal-perturbation analysis with test results was satisfactory. In the latter case, some uncertainty remains about the electrical behavior of sectional wedges in the generator rotor slots during the tests. Although this factor seems to have been correctly accounted for, further test verification may be desirable.

Substantial progress was made in the fourth objective. Two modeling approaches were pursued. The first involved exact solution of the time-varying magnetic vector potential equation, including nonlinearities in the generator magnetic circuits. This model was satisfactorily formulated and exercised. The second model involved the introduction of variable iron permeabilities into the magnetic linear diffusion equation. This approach can be only approximately correct; however, its solution is anticipated to be more economical than the first, exact method. This method was also satisfactorily formulated and solutions were demonstrated. Both methods were exercised on a common problem—a ferromagnetic slab of simple geometry—over a wide range of flux density excursions. The results from both methods were in reasonable agreement. Thus, the concept of a useful large-signal method has been demonstrated.

The methods developed and validated during these projects are suitable for provisional use in generator analysis. Their introduction should be made on an evolutionary basis, with further test and calculation correlation on a number of different generator geometries. Methods for fine-tuning the calculations may be developed as part of this evolutionary process. *Project Manager: D. K. Sharma*

POWER SYSTEM PLANNING AND OPERATIONS

Data transfer and conversion

As power systems have grown and higher voltage interconnections have been made, the need to exchange power flow and stability data for planning and operations has increased severalfold.

Data transfer between areas is complicated by noncompatible model formats in different computer programs used to model the same problem. Such different models result from valid but different applications of engineering principles.

As the amount of data to be converted from one format to another has increased, utilities have developed additional computer programs to automate data conversion. Over the last two decades, three specific formats have evolved and become widely recognized as major exchange formats for power flow and stability data: the IEEE common format (widely used in the eastern United States), the Western Systems Coordinating Council (WSCC) format (widely used in the western

United States), and the Philadelphia Electric Co. (Peco) format (used by utilities and power pools utilizing the computer programs that were developed by Peco and the Pennsylvania-Jersey-Maryland Interconnection.

Some examples of model differences in these formats for the same piece of physical equipment are that WSCC transformer models allow for taps on both sides of the transformer, while the IEEE common and the Peco formats do not. The WSCC format also allows long transmission lines to be represented in sections (transparent to the user), as well as unbalanced pi representations. Moreover, static and dynamic equivalents are not necessarily interchangeable. When a set of data for a model is transformed into an equivalent model for the transfer of data, it should be possible to re-create the original model by reversing the transformation process. This, however, is often not the case in actual practice.

Data transfer and conversion is a procedure used for two primary purposes: the periodic exchange of data (between two or more organizations, such as utilities, pools, and reliability councils) and parallel program input (resulting from the development or installation of a new computer program that requires the same data used by other computer programs).

Boeing Computer Services, Inc., has begun a project to prepare a single computer program (a preprocessor) to handle conversion of both power flow and stability data (RP1917). This preprocessor will act as a unified input handler for EPRI programs, as well as to translate directly from and to each of the major interchange formats (IEEE, Peco, WSCC).

Transfer of larger and more varied data for other programs, such as those used for long-term dynamics and generation/transmission planning studies, has not yet received substantial attention; thus the procedures and formats have not yet been widely established. (Examples of such data are automatic generation control data and power plant auxiliary data.) The preprocessor will be designed to provide a basis for future input in other program areas.

The current phase of EPRI's contract will provide a set of short-term translators for power flow and stability, as well as the design for the midterm preprocessor approach. This phase will be complete by the end of 1983. *Project Manager: John Lamont*

DISTRIBUTION

Surge arrester tester

Measured by any standard, the reliability of equipment used on utility distribution systems is enviable. Failure rates of most equipment are almost always below 0.5%/yr and commonly below 0.3%/yr. But because distribution equipment is used in such huge quantities—hundreds of millions of some items are in service—even the very low failure rates result in a substantial number of actual failures per year.

This is certainly true of surge arresters (over 100 million are in service), and the annual failure rate is perhaps 0.2%/yr. This means that quite a few actually fail, of which somewhat less than half fail with some degree of porcelain breakage.

EPRI has developed a design and manufacturing technique that will substantially reduce, if not eliminate, the probability of fragmentation during failure (RP1470). This technology can be applied to new arresters but cannot be retrofitted to existing arresters.

Another project is to develop a low-cost device for checking the condition of surge arresters in-service and from a distance (RP2004). With such a device, existing arresters could be checked either on a routine basis or before work is performed in the vicinity of energized arresters.

Over 200 used arresters were obtained and tested extensively to see whether any externally measurable characteristic indicated impending failure. Unfortunately, most of the arresters were "good," thwarting the effort to find a failure signature. Because moisture entry is probably the primary cause of arrester failure, the contractor, McGraw-Edison Co., started a large number of arresters toward failure by injecting water and aging them at rated voltage. They were monitored regularly to search for characteristic changes that would be an indicator of impending failure.

From the beginning of the project, the requirement that the device give a remote indication suggested an approach based on radio noise emission. Although other possible indicators were not ignored, considerable stress was placed on the monitoring of electromagnetic radiation. As the water-contaminated arresters aged, a characteristic radio noise emission was detected. The contractor is now developing a suitable receiver to recognize this pattern.

In addition, investigation showed that a somewhat similar pattern could be produced by other equipment operating under abnormal conditions that might exist on a distribution line. The tester might be designed to pinpoint not only failing arresters but also other undesirable conditions. Whichever direction is selected, EPRI expects to have a handheld, convenient, and inexpensive device developed and tested by the spring of 1984. *Project Manager: Herbert Songster*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

PLANNING MODEL FOR UTILITIES

EPRI has sponsored the development of a comprehensive strategic planning model for the utility industry (RP1819). This project was begun in 1981 in response to widespread industry interest in a comprehensive, integrated, flexible, and aggregated strategic planning tool that would explore the broad and fundamental changes facing the industry. Arthur Andersen & Co., the principal contractor, has recently completed and thoroughly tested the prototype version of the utility planning model (UPM) and is currently helping four utilities conduct field tests. The experiments will be completed by the end of 1983 and the system released for general utility use by early 1984.

The industry's ability to anticipate and predict future trends has changed fundamentally. In the past, utility planners could easily predict trends in load growth or costs because such trends were stable and consistent from period to period. These factors have become very uncertain, and utilities' ability to plan well for an uncertain business environment is correspondingly difficult.

Utility corporate planners realize that new types of analytic techniques, including automated models, are needed to deal with this changed environment.

There are several factors leading to the need for new techniques. Utility planning can no longer remain compartmentalized. All aspects of planning affect and are affected by all other aspects from sales forecasts to financial plans. Corporate planning models must be integrated and comprehensive to take such real-world interactions into account.

Point forecasts and rigid plans are too limiting. Planners must be able to test alternative scenarios and contingency plans. An agile model, which can be set up and run under alternative sets of assumptions rapidly and conveniently, is tremendously useful in such situations. Such a model does not take the place of more detailed, more accurate models; it complements them by approximate, far-ranging screening.

To reflect and analyze new problems and opportunities as they arise, a corporate modeling tool must be flexible, easy to use, and easy to modify and redirect by planners. A modeling tool having significant user-friendly features is particularly helpful in such an unstructured decision-support environment.

Over the last few years the need for such a model for corporate and strategic planning has become more apparent. Although some tools existed, industry advisers believed a substantial improvement was needed to meet current challenges. Therefore, EPRI was requested to design, build, test, and demonstrate an advanced, comprehensive modeling system and make it available to the industry.

At the outset, it was decided that building and designing such a model for utility planners required the cooperation and advice of those same planners. Like other EPRI model development projects, it was organized around three groups: EPRI, a principal contractor, and an advisory group of potential utility users.

The advisory group was broken into three smaller bodies for maximum user input. A large group of more than 70 companies agreed to serve as general observers. These companies monitor progress by participating in periodic workshops and reviewing written reports. A core advisory group of 14 participates much more intensively. This group advised on the selection of the contractor, and it works closely with the contractor and EPRI in specifying design, implementation, and testing decisions.

One company has directly contributed extensive resources to the prototype system development, and three companies have further agreed to serve as test case sites for the system. A fourth company, feeling some urgency to have such a system operational on its system, is also serving as a test case. Commonwealth Edison Co. has worked with the contractor on system design, coding, and testing, contributing computer time and the services of a full-time analyst. Georgia Power Co., Northeast Utilities Service Co., and Wisconsin Electric Power Co. are currently testing the system in their own organizations and adapting it to their needs in a real-world context; Florida Power & Light Co. has initiated testing on its own. The efforts and experiences of these five companies will serve as the model's final critique.

The project has four phases. Phases 1 and 2 were completed in April 1983. The first phase, design and scoping, was a six-month cooperative effort by the contractor, EPRI, and the core advisory group. It culminated in a preliminary report documenting the consensus reached with regard to the conceptual design of the system, the level of design to be represented, and the functions and features to be provided. A second outcome of Phase 1 was a workshop at which the system design was presented and reviewed by representatives of the general advisory group.

Phase 2 culminated in a system prototype, complete with a representative data base and full documentation, fully tested in cooperation with analysts at Commonwealth Edison, where it was developed. The system reflects all important design features and facilities agreed to in Phase 1 and is currently being used in the case study phase (Phase 3) of the project. Phase 4 will be ongoing maintenance and support.

Figure 1 is a simplified schematic of the modeling system. The system simulates the entire sequence shown in the figure annually up to 30 years. Results are reported annually in all areas of interest to the planner, including load, revenues, production, construction, finance, and regulation.

Several important features of the modeling system are innovative for utility analysis. The system is completely integrated. As Figure 1

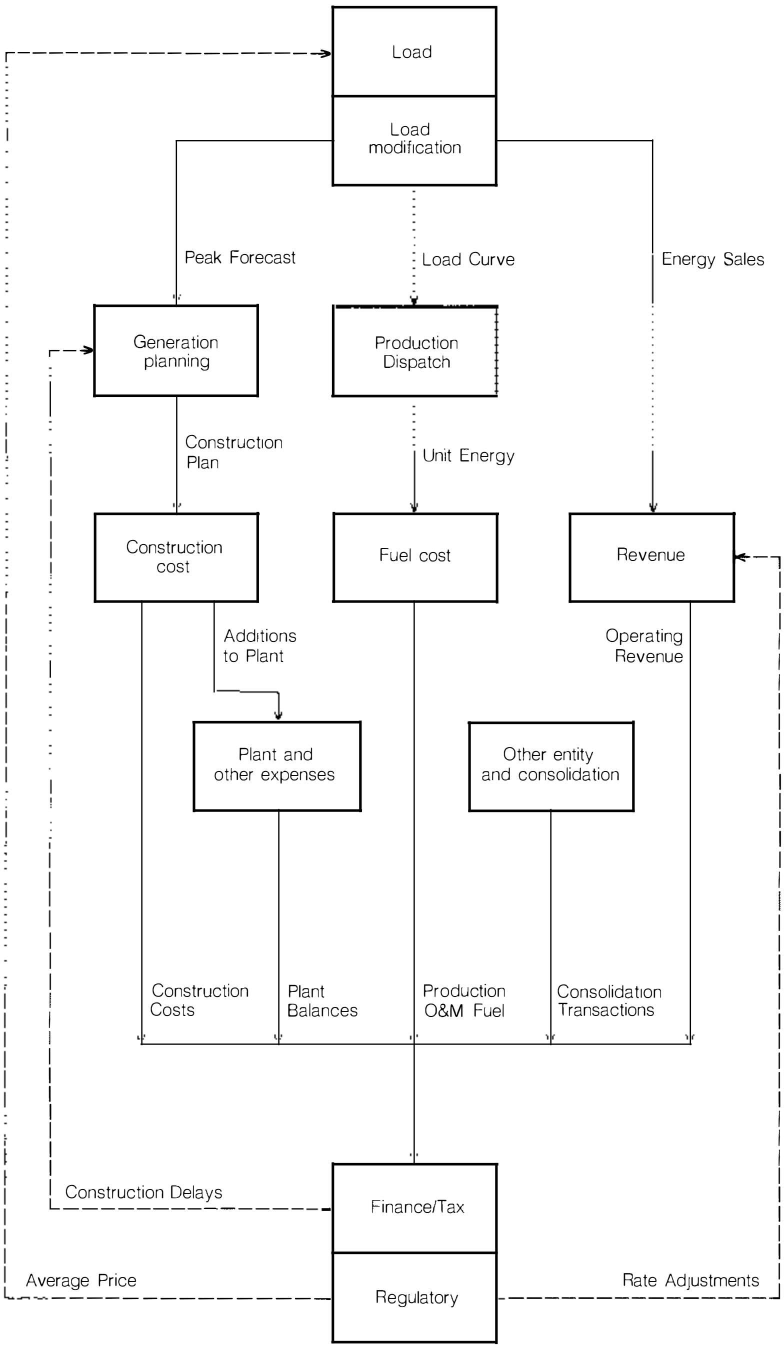


Figure 1 A simplified schematic of the utility planning model. Highlights of the UPM design: an integrated system, complete with important feedback (e.g., price elasticity, dynamic generation planning, and regulatory lag); a comprehensive system in which all analytic activity is represented; a user-friendly decision-support system.

illustrates, all modules are linked, and each must be run in a given year before any module can be run in the next year, which eliminates the possibility of generating partial analyses independent of other parts. This facility, known as round-robin execution, ensures a complete and integrated analysis.

A number of significant feedback facilities have also been built into the system for additional integration. The most important of these are the adjustment of demand growth to changes in production cost and price, the adjustment of system plans to changes in demand growth over time, and adjustment of construction schedules on capital projects to changes in financial performance. Feedback is not compulsory in the system, however. Any or all of the feedback capabilities can be turned off for any given use. This facility is important because a simultaneous solution to an integrated system can sometimes be complex, nonintuitive, and difficult to interpret, and a simultaneous solution is not always necessary.

The system presents a completely comprehensive picture of utility analysis, both in terms of a utility's present structure and in terms of most potential changes that may evolve. As the figure shows, all current planning and operating phenomena are represented and integrated, including load projections, capital expansion plans, system operations, fuel supply, construction spending, customer classes, revenues, taxes, accounting, financing, and regulation. In addition, future considerations, such as demand-side investments, fuel subsidiaries, and other nonutility businesses, can be represented and consolidated into the analysis. The system can also be structured to represent multiple legal entities and/or multiple jurisdictions for utility or nonutility businesses, as required in particular circumstances.

The system, programmed in a fourth-generation modeling language to facilitate documentation and user modification, is designed to be a user-accessible decision-support system. Specialized user procedures are being designed for data entry, report writing, and graphics display. Specialized internal data handling is also being designed. This so-called accordion facility will allow users to expand or contract data arrays to facilitate addition or subtraction of variables and modification of algorithms. These facilities make the system convenient, flexible, and modifiable by diverse users to suit different situations and multiple issues.

Case study experiments are currently being carried out at Georgia Power, Northeast Utilities, Wisconsin Electric Power, and Florida Power & Light by user teams, which include personnel from each of the four companies, the contractor, and EPRI. Preparations are complete, including defining the system configuration that most effectively represents company situations and needs, collecting and validating data consistent with that configuration, and choosing a proper test problem.

Each case study consists of two major parts. First, the system was calibrated. It was run on in-house computers and tailored to a company-specific configuration. Company-specific data were loaded, and an acceptable company-specific base case was generated. Base case generation was not straightforward and required iterative tailoring and modification. Second, the teams are using the calibrated system to analyze and report on an issue of interest to each company. This part defines the problem and the study structure, uses the modeling system to carry out the study, and interprets and reports results.

The four experiments are scheduled for completion early in 1984, when a workshop will be held and a final report written. Early in 1984 the model will be available to the utility industry and other interested parties. EPRI plans to continue ongoing maintenance and support to new users. Present plans call for arrangement of model distribution and support software by an EPRI computer services contractor and the establishment of a user group.

The user group will be the cornerstone of EPRI's continuing support of the modeling system. Important responsibilities of the group will include periodic new-user training sessions; basic help in mounting and calibrating the system; a central clearinghouse for reporting, review, and implementation of user-identified enhancements; and regular user meetings to provide a forum for problem and solution exchange. *Project Manager: Lewis J. Rubin*

MARKET PENETRATION ANALYSIS

Electric utilities need accurate estimates of the market penetration of end-use technologies for forecasts and planning. Market penetration analysis is difficult, however, because many complex demographic, engineering, and financial factors must be taken into account, as well as the uncertainties that affect them and the consumer response to these factors. Further, utility analysts must choose from a wide range of available methods. To help utilities with their planning needs, EPRI reviewed and evaluated the content, performance, and appropriateness of the many methods used to estimate end-use technology market saturation (RP2045). The principal objective of Phase 1 was to provide a framework for matching methods with applications.

The project reviewed analytic approaches from such fields as operations research, economics, technology substitution, market research, and behavioral psychology. Although these fields overlap somewhat, they often use different premises and terminology. It is important, therefore, for analysts to understand the similarities and differences so they can choose and use the methods more effectively.

Taxonomy of methods

Methods can be categorized by distinguishing three levels of a market penetration analysis (Figure 2). A forecast of the number of units per year, the objective of any such analysis, can be obtained by such methods as diffusion/logistics curves. However, a more complete analysis may develop separate estimates for the ultimate market potential and then superimpose estimates for market share. The third level may involve some characterization of consumer behavior, which must then be interpreted through some set of assumptions to estimate market penetration (e.g., a "probability of purchase" may become the "market share"). Each of these methods is discussed in *Market Penetration Analysis for End-Use Technologies* (EPRI EA-2702).

Penetration models make forecasts either directly or on the basis of input from linked analyses. Model types include time series, econometric, historical analogy, equipment stock, and diffusion methods. (As used here, *diffusion* refers to the logistics curve methods and not to the entire process of technologic change, as the term is sometimes used.) These methods range widely in predictive ability, explanatory power, and practicality of use.

For market potential methods, optimization refers to the set of mathematical programming techniques used to determine an optimal technology or product mix within constraints. Preference interpretation is not actually a method, but refers to the step by which a prediction of consumer behavior is translated into a penetration forecast or estimate of market share.

Consumer preference methods study and predict attitudes and purchase decisions. Cost models are the simplest. Costs and discount rates are the basic decision variables, and relative costs are interpreted as long-run market share. Discrete choice models are used to estimate probabilities of purchase on the basis of the value assigned to a product's set of attributes. Hedonic pricing models develop value indexes of a product's characteristics, and multiattribute methods estimate an individual consumer's ranking of products on the basis of ranking a product's characteristics. This final set of methods is popular with economists as well as market researchers and requires input from surveys and other data-gathering techniques.

Selecting methods

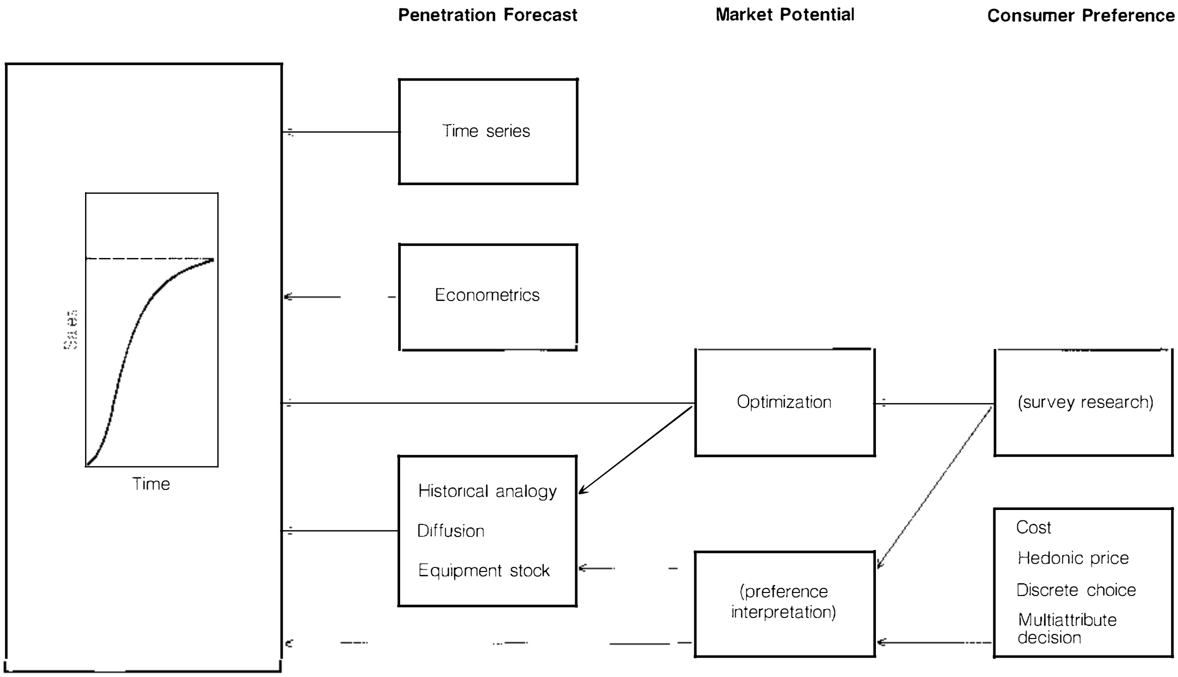
The net value of an analysis (using the terms *value* and *cost* in their broadest sense) depends in part on the potential impact of the technology being studied and the uncertainty of that impact. The value of the information is weighed against the cost of the analysis, which depends on the complexity of the method, the time span, data availability, and so on. Although such a trade-off analysis is not always explicitly done, it is nevertheless implicit, and specific criteria can help in method selection.

Choosing a method requires three basic steps of an iterative process: determine the purpose of the analysis; characterize the market; and apply selection criteria. The purpose of market penetration studies in an electric utility can range from a response to a specific management query to ongoing periodic planning (e.g., sales or load shape forecasting). Not only will the immediate purpose and context of an analysis strongly influence the choice of method, but a user may actually be seeking more from an analysis than simply a forecast of penetration by a given technology. For example, the results may indicate ways in which the utility can influence the market penetration of a particular product.

The market in which the product competes must be characterized in some detail. The relevant market, its size and growth (historical and future), and competing products must all be identified. It is important to consider such features as the size and character of market segments (e.g., retrofit or new construction), historical sales, manufacturing-supplier-distribution channels, regulation, competition (number of suppliers, market shares), R&D (likely innovations), and sensitivity of the market to economic conditions. Relevant competing products that substitute alternative fuels and link end uses may also be important (e.g., space heating and water heating, space heating and air conditioning). Separate markets can also be linked, as in the case of cogeneration.

A review of the characteristics of the market should provide a basis for under-

Figure 2 Methods for market penetration analysis have three levels of techniques, some of which may be linked together. Some methods can forecast penetration directly; others characterize consumer behavior more explicitly.



standing the forces apt to affect the market penetration of a product and thereby guide selection of the appropriate methods.

A number of criteria should be considered in selecting methods.

- Potential impact of the end-use product on utility performance
- Uncertainty of potential effect
- Characteristics of the end-use technology
- Time span being analyzed
- Extent and nature of the data available to the utility
- Resources available for the analysis
- Acceptability by the user

The criteria are not mutually exclusive and hence the process of reviewing the methods against the criteria must be iterative.

What impact will the end-use technology have on the utility itself? Examples of possible measures are kWh sales, MW generation capacity, generation mix; system reliability; financial measures (e.g., cost/kWh, earnings per share, stock price); utility image; and regulatory views.

If the probable impact is assessed as low, resources devoted to the analysis and the complexity of the method can be minimized. For example, historical analogy, trend extrapolation, or time series models may be most appropriate. The reverse is true if a product may have a high potential impact on a utility. In this case, a more sophisticated and detailed method may be necessary.

Uncertainty

Analysts have to make judgments about a number of uncertainties, including future total market size, the future likelihood of yet unknown technologic innovations; the cost and performance of products recently released to the market (e.g., solar photovoltaic systems); and the future availability and cost of different fuels.

A four-quadrant framework was developed for high and low values of potential impact and uncertainty of impact. Two nonstrategic (i.e., low importance) quadrants can be distinguished by the degree of risk: a high-risk strategic quadrant where the utility is in a position of vulnerability (or opportunity), and a low-risk strategic quadrant where the utility might be able to influence the technology's effect because it is less uncertain. Table 1 shows this framework together with some products of interest to utilities. For example, advanced electric heat pumps may have a large effect on the utility's performance, but just how large that effect would be is uncertain. A high-risk strategic product probably warrants a more sophisticated analysis.

Generally, characterization of the end-use product should include all the aspects of a product considered by consumers, such as initial cost, operating cost, application, availability, reliability, image, and competitiveness.

Another important consideration is the product's stage of development. For example, if a product is in the preprototype/development stage, the uncertainty about

Table 1
SELECTION OF A MARKET PENETRATION ANALYSIS METHOD

	Low Potential Impact	High Potential Impact
Low Uncertainty	Low risk—nonstrategic quadrant (e.g., thermal storage; office equipment) Historical analogy Time series models Econometric models Diffusion models	Low risk—strategic quadrant (e.g., cogeneration; central air conditioning) Historical analogy Diffusion models Hedonic price models Cost models
High Uncertainty	Moderate risk—nonstrategic quadrant (e.g., heat pump water heaters) Time series models Econometric models Hedonic price models Cost models	High risk—strategic quadrant (e.g., electric vehicles; advanced heat pumps) Equipment stock models Discrete choice models Multiattribute decision models Survey research

that product's cost and performance is high. Historical analogy or cost models may be better able to accommodate this uncertainty than others. For each of the six stages in the product life cycle (idea, development, prototype, new market entrant, rapid growth, and mature product), different methods are appropriate. For example, survey and consumer preference methods, in combination with a stock model, are well suited to the rapid growth phase.

The time horizon for a market penetration estimate will typically affect the choice of method. In general, methods that can consider various stages in the product's life cycle (e.g., diffusion models) are useful for long-term forecasting. Time series models, however, can be applied for all time horizons. Econometric models using regression techniques and optimization models tend to be best suited for medium- to short-term forecasting. Consumer preference methods are well suited for projecting short- to medium-term product demand.

Data requirements

Simple historical analogy and trend extrapolation require limited data. Other methods, such as discrete choice models and hedonic price models, need substantial data.

The availability of a range of possible values for key data items may also determine method selection. For example, in an analysis of an electric vehicle, probability distributions of key variables, such as the cost of batteries, the distance between recharging, and the year of market introduction, would enable the analyst to conduct a more sophisticated analysis than deterministic or point estimates for these variables.

Utility resources required to implement a given method are also important. They depend on a number of factors, including the type of method and its complexity, data requirements, computer and human resources, and whether the utility will continue to use the methodology. The costs associated with each of these factors depend on both the method and the situation. Typically, the more details required on customer characteristics, the higher the cost of data collection, verification, and analysis.

Method acceptability

Whether the user of the analysis accepts the method depends on its complexity, the timeliness of its forecasts, and the level of knowledge required for application. The user must understand the method and feel comfortable that it represents a "correct" approach. Market penetration analysts and analysis users are frequently not the same person. Analysts may have specialized staff functions and users may be decision makers in line positions elsewhere in the organization. An organization's use of analytic methods may also change. It may be necessary to first introduce relatively straightforward, intuitive methods before proceeding to more-complex, yet possibly more-accurate, ones.

To support utilities' increasing use of market penetration of various end-use products, EPRI has systematically reviewed and evaluated the alternative analytic methods available to planners.

In Phase 2 of RP2045, now in the planning stages, EPRI will conduct case studies in collaboration with individual utilities so that various methods can be tested for their ability to analyze the penetration of specific end-use technologies in real markets. Utilities with an interest in this area of research should contact the project manager. *Project Manager: Edward Beardsworth*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

FUEL CELL USERS GROUP

The main objective of EPRI's Fuel Cell Program is to expedite the commercial introduction of first-generation phosphoric acid fuel cells for dispersed power plant applications. Commercializing any new generation technology is difficult, and the difficulties have increased because of problems faced by the utility industry, such as decreased load growth, high and unstable fuel prices, and expensive capital. A number of utilities recognized the importance of fuel cells as an efficient, modular, rapidly deployable, and environmentally acceptable generating option. These utilities were also anxious to expedite the commercial availability of fuel cell power plants and in 1980 asked EPRI to assist in forming the Fuel Cell Users Group (FCUG) to serve as a focal point to stimulate the fuel cell commercialization process. This report describes some of the activities of FCUG and the status of complementary EPRI projects. The background of FCUG was described in previous EPRI Journal *articles, the most recent in October 1982, p. 56.*

Established in April 1980 with 37 charter members, FCUG now includes 55 utility members and 8 nonelectric utility associate members. The members are a diverse group of utilities located in over 30 states and Canada. They represent large and small, investor-owned, cooperative, and municipal utilities, as well as their respective trade associations.

The main objective of FCUG is to expedite the commercialization of phosphoric acid fuel cell power plants (FCPPs) for electric utility application. In this pursuit, the activities of the group are fivefold.

- Assist the fuel cell developers in defining fuel cell system requirements and specifications for electric utility application and the market potential for fuel cell systems having these specifications
- Identify, sponsor, support, and participate in research, development, engineering, demonstration, and use of fuel cell energy systems
- Identify utilities that are candidates for commercial prototype and early commercial power plants and stimulate utility interest in early commercial market commitments
- Coordinate work and exchange information within the utility industry and with other public or private organizations concerned with the development and future use of fuel cells
- Encourage the development of fuel cells by interacting with the utility industry, government agencies, developers, and others

To achieve these objectives, FCUG has been structured into a series of committees and subcommittees to address commercial readiness and commercialization issues. A 15-member board of directors, consisting primarily of utility chief executive officers, provides overall policy and guidance. The Management Committee and the Executive Committee provide the planning and evaluation functions, while three technical subcommittees investigate issues involving system planning, fuels and fuel processing, and engineering and operation. Three other subcommittees communicate with members and initiate new-member programs; investigate the financial benefits of fuel cells and possible financing mechanisms; and interact with the federal government and utility, vendor, and environmental representatives to engender continued support for fuel cell programs. The activities and accomplishments of these groups and of the complementary EPRI projects are summarized below.

Fuel cell applications study

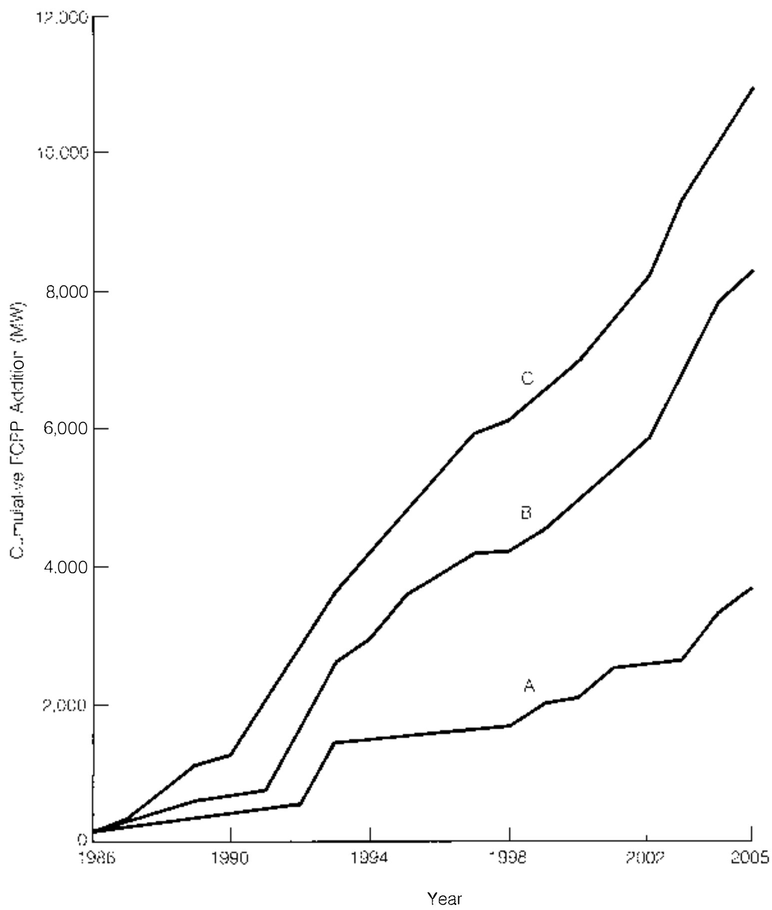
For the past 18 months, the System Planning Subcommittee of FCUG, jointly with EPRI, has been investigating fuel cell applications of 37 specific utility systems representing over 30% of U.S. electrical demand (RP1677-6). This project, the applications study, focuses on using conventional system planning tools, a common set of technical and economic data from the 1982 *Technical Assessment Guide* (EPRI P-240-SR), and system data from the 37 utilities to produce a credible series of optimal generation expansion plans using, as alternatives, conventional technologies and fuel cells.

Using traditional economic analyses, initial results for 25 of the 37 utilities (Figure 1) indicate that fuel cells using natural gas or petroleum liquids with a price equal to that of No. 2 fuel oil can penetrate into the utility generation mix (Curve A). This relatively high cost of natural gas is a conservative assumption and forms the basis for parametric studies using lower fuel costs. The results also demonstrate that specific benefits obtained from dispersed fuel cell application—primarily benefits associated with cogeneration, transmission and distribution system savings, and air emission advantages—can lead to a doubling or tripling of fuel cell additions over the 20-year study period (Curves B and C).

Other observations of this study are (1) that fuel cells can be economically dispatched after nuclear, hydro, and coal units, and generally operate in the 10–25% capacity factor range for the studied utilities; (2) that where new large baseload units could not be brought on line quickly, fuel cells operating at a 50–60% capacity factor were added; and (3) that fuel cell application appeared most prevalent on coal-based systems with little existing cycling and peaking capacity and least prevalent on oil- and gas-fired systems where new nuclear and coal units were the most economical and where existing oil and gas units could be shifted to cycling and peaking duty.

Sensitivity studies on four representative utilities indicate fuel cells using natural gas

Figure 1 Cumulative annual MW additions of fuel cell power plants. Curve A shows fuel cell additions of 3660 MW, or 3.6% of total capacity added if fuel cells provide no benefits ($0/kW); Curve B, 8220 MW, or 8.1% if base benefits supplied by 25 of the 37 utilities are used ($166/kW); Curve C, 10,930 MW, or 10.8% if high average benefits are used ($240/kW). Sufficient utility reserves combined with low load growth projections will keep fuel cell and total capacity additions relatively low between 1986 and 1992. As the need for capacity takes shape about 1992, fuel cell penetration will increase.



priced at two-thirds the cost of No. 2 fuel oil would expand fuel cell additions on oil- and coal-based utility systems, unless coal capital costs significantly less than $1000/kW could be obtained; and utility systems with large numbers of gas-fueled units would be more likely to make better use of these existing units and add new, more-economical coal plants. Further, increased load growth would stimulate larger additions of fuel cells, as well as the alternative generation technologies.

Fuel cell breakeven capital costs for the 25 utilities initially studied ranged from $400/kW to $1000/kW (1981 $). This did not include any value that might be placed on such fuel cell benefits as T&D savings, modularity, or low emissions that are associated with fuel cell applications. The 25 utilities provided estimates of fuel cell bene-

FCUG MEMBERS

Investor-owned Utilities
- Baltimore Gas and Electric Co.
- Boston Edison Co.
- Central Hudson Gas & Electric Corp.
- Central Illinois Light Co.
- Consolidated Edison Co.
- Dayton Power and Light Co.
- Delmarva Power & Light Co.
- Duquesne Light Co.
- Edison Electric Institute
- Green Mountain Power Corp.
- Hawaiian Electric Co.
- Idaho Power Co.
- Kansas City Power & Light Co.
- Long Island Lighting Co.
- Mississippi Power & Light Co.
- Niagara Mohawk Power Corp.
- Northeast Utilities Service Co.
- Ohio Edison Co.
- Philadelphia Electric Co.
- Public Service Co. of Oklahoma
- Public Service Electric and Gas Co.
- San Diego Gas & Electric Co.
- Southern California Edison Co.
- Southern Company Services
- Tampa Electric Co.
- Toledo Edison Co.
- Utah Power & Light Co.
- Virginia Electric and Power Co.

Federal Utilities
- Rural Electrification Administration
- Tennessee Valley Authority

Municipal Utilities
- American Public Power Assoc.
- Anchorage Municipal Light & Power Dept.
- Easton Utilities Commission, Md.
- Jacksonville Electric Authority, Fla.
- Lincoln Electric System, Nebr.
- Los Angeles Dept. of Water and Power
- Massachusetts Municipal Wholesale Electric Co.
- Memphis Light, Gas and Water Div.
- Missouri Basin Municipal Power Agency
- Provo City Power, Utah
- Santa Clara Electric Dept., Calif.
- Taunton Municipal Lighting Plant, Mass.

Canadian Utilities
- Hydro-Quebec
- Ontario Hydro

Cooperative Utilities
- Adams Electric Cooperative
- Allegheny Electric Cooperative
- Brazos Electric Power Cooperative
- Buckeye Power, Inc.
- Colorado Ute Electric Association
- Hoosier Energy Rural Electric Cooperative
- Lee County Electric Cooperative
- National Rural Electric Cooperative Association
- Seminole Electric Cooperative
- Southern Maryland Electric Cooperative
- United Power Association

fits that ranged from $63 to $610/kW. Including such benefits can increase the breakeven capital cost on a dollar-for-dollar basis.

The System Planning Subcommittee and the system planners from the studied utilities have reviewed all these results and have accepted the study results as reasonable, given the input parameters. An additional 12 utilities, representing 60,000 MW of demand, is undergoing a similar analysis now. The System Planning Subcommittee is also working with EPRI to develop and publish a guide for system planners to help them evaluate fuel cell power plants on utility systems. This guide will assist the reader in better understanding the fuel cell, its characteristics, and its potential benefits, and will describe some appropriate evaluation techniques.

Other subcommittee issues

The Fuels and Fuel Processing Subcommittee is currently investigating fuel price and availability of probable fuel cell fuels. These investigations project that natural gas (or methane from various conventional and unconventional sources) will be available through 2010 as a utility fuel for fuel cells. In addition, as shown in Table 1, the group concludes that the price of methane will remain relatively stable in real terms for the remainder of this decade with small real price increases occurring in all fuel segments during the following two decades. Because some utilities may not have access to natural gas in all cases, or because of short-term aberrations in its availability or price, the subcommittee report suggests that some utilities will want to seriously consider dual fuel capability. Although in the past naphtha has been considered a prime backup fuel candidate, propane's availability and price make it the long-term preferred fuel, but further study is necessary to determine its potential as a utility fuel.

The Engineering and Operations Subcommittee continues to provide utility feedback to the two domestic fuel cell manufacturers: United Technologies Corp. and Westinghouse Electric Corp. The subcommittee is currently reviewing the results of an EPRI project with Kryos Energy, Inc., which evaluated one manufacturer's proposed commercial design based on experience gained with the 4.5-MW unit in New York City, and EPRI funded commercial design activities (RP842-2, RP1777-1, RP1777-2). This work concluded that the supplier's latest design is based on commercial design parameters, is easier to start up and shut down than the 4.5-MW unit, uses more commercially available components, and contains fewer total parts than the 4.5-MW unit.

The subcommittee is also continuing to develop quality assurance guidelines for fuel cell fabrication, as well as installation, operation, and maintenance guidelines. Participation on the committee by engineers from utilities that have expressed serious interest in the first commercial prototype units adds to the usefulness of the group's work.

First commercial units

Commercial introduction of the first-generation fuel cell is envisioned as a two-phase process. First, both manufacturers are expected to install two or three commercial prototype power plants on utility systems. Second, in parallel with the installation and initial operation of these prototypes, the manufacturers would complete facilities for limited quantity production of the first commercial power plants (~20 units) and revise the design of these plants on the basis of experience gained from prototype operation. Both the manufacturers of fuel cells and the utility buyers need assurances that once the prototype units operate successfully (in 1986 or 1987), purchase of follow-on commercial units will take place shortly thereafter. The timing of other follow-on units is important. A utility considering an early commercial plant purchase (in order to gain experience with fuel cells before large orders are placed) would probably receive this first unit in 1988 or 1989. Assuming that a one-year period of operating experience is required before a decision to purchase additional units can be made places the utility decision point for fuel cells or other generation about 1990 at the earliest. The application study of the System Planning Subcommittee found fuel cell capacity additions increasing rapidly in the mid 1990s. Thus the two-phase commercial introduction process must begin now so that utilities can order units later on with confidence in their operability and economics and manufacturers can have the needed fuel cell production capacity available in the early-to-mid 1990s.

Table 1
PROJECTED PRICES FOR PROBABLE FUEL CELL POWER PLANT FUELS
(1983 $/10⁶ Btu)

Fuel	1983	1990	2000	2010
Natural gas	2.90	3.80	5.50*	6.70*
Naphtha	6.60	6.60	8.00	9.80
No. 2 oil	6.20	6.20	7.60	9.20
Methanol	7.00	16.00	19.00	20.00
Propane	5.50	5.50	5.50	5.50
Residual oil	3.90	3.90	4.70	5.80

Source: Report of the FCUG Fuels and Fuel Processing Subcommittee, July 1983.

Note: Prices at the wellhead or refinery. Transportation costs are not included.

*Natural gas prices in these periods may not rise above those of competitive fuels in local markets.

Although all the activities of FCUG mentioned previously are necessary and help to build the basic confidence of FCUG and others in the fuel cell, more must be done to inform and educate utility decision makers about fuel cells and how only utility interest and action will bring about commercialization. The FCUG board of directors has recognized this and is considering a multifaceted plan to spur the commercialization process. The key elements of the plan include the following.

- A broad-based communication program to reach out to both FCUG and other utility decision makers. This is aimed at raising the interest levels of utility managers and executives in fuel cells and at encouraging utility evaluations of fuel cell applications and benefits on utility systems.
- Expression of serious interest in the first commercial units will be promoted.
- More utility participation in funding discrete technology development tasks essential to commercialization will be encouraged. DOE and EPRI funding has been supplemented in the past by a few utilities. Greater utility participation in these tasks will strengthen utility interest.
- Potential financial shortfalls in prototype or first commercial orders will be monitored and potential solutions to their elimination developed. This could include some combination of EPRI, utility industry, or manufacturers' assistance, innovative third party financing, or other unique solutions to the problem.

Today's environment has created a need for new and innovative ways of commercializing new technologies. FCUG has become an important focal point in the commercialization of the fuel cell. As manufacturers prepare to offer and fabricate the first prototype units, FCUG must be in a position to assist utilities interested in these and the follow-on initial commercial units. FCUG is demonstrating that a group of potential users, working with DOE, EPRI, manufacturers, and the utility industry, can provide a valuable addition to the commercialization of the fuel cell. *Project Manager: David M. Rigney*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

LOW-LEVEL RADIOACTIVE WASTE DISPOSAL

Low-level waste (LLW) disposal is best characterized as being in a state of transition. As recently as 1975, the disposal of such wastes was viewed as a rather straightforward proposition. Costs were in line with other operating expenses, and burial site availability was assumed. Since then, however, events have combined to create much uncertainty about costs and site availability. As a result, utilities are in the position of having to make long-term disposal plans without sufficient information on many of the controlling variables. EPRI is helping to provide utilities with the information they need through projects on all aspects of LLW disposal, ranging from waste assay methods to solidification criteria to process options and economics.

LLW transportation and burial charges have increased dramatically in recent years. As shown in Figure 1, the cost of disposing of a 55-gal drum of LLW was approximately $15 in 1975; today it is $150. Questions about burial site availability have also arisen. In 1978 the state of South Carolina initiated a policy of volume restrictions on the waste generators using its Barnwell site. The resulting uncertainty was compounded by the Low-Level Radioactive Waste Policy Act of 1980, which declared that by 1986 each state was to be responsible for waste generated within its borders. This has led to the current negotiations to form state waste disposal compacts.

In response to the changing situation faced by utilities, EPRI is sponsoring much research on LLW disposal. This report focuses on studies of advanced volume-reduction (VR) systems, waste minimization techniques, and the economics of LLW disposal.

Advanced VR technology

As a result of increasing disposal costs and burial site uncertainties, utilities are considering advanced radwaste VR systems. EPRI's initial effort in this area (RP1557-1) sought to identify the various systems available and to characterize them in a way that would aid in utility planning. Information was gathered on VR systems commercially available in this country. Non-U.S. systems were also reviewed because their penetration into the U.S. market is considered very likely.

Visits to Japan and Europe confirmed that the implementation of VR technology elsewhere in the world is several years ahead of U.S. experience. These visits provided considerable insight into the diversity of systems and techniques available, several of which are directly comparable to offerings in this country. The processing experience of other countries can serve as a valuable informational resource and in some cases can clearly demonstrate the appropriateness of a given technology. This is especially true for LLW incineration, which has been in use abroad for over a decade.

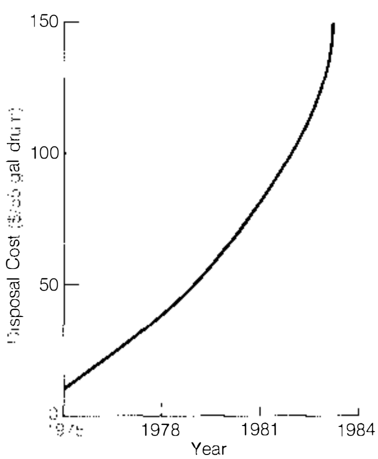


Figure 1 Costs for disposal (transportation and burial) of drums of dry low-level radioactive wastes. Since 1975, these costs have risen continuously. Transportation costs have increased with oil prices, and burial costs have increased because of higher site operating expenses and higher state charges.

Two very different VR technologies are emerging as the leaders in the U.S. market. One is Aerojet Energy Conversion Corp.'s fluidized-bed incinerator-dryer, which has received eight orders to date. The other is WasteChem Corp.'s bitumen solidification system, which has been ordered for six nuclear stations.

The Aerojet Energy Conversion system is designed to process concentrated liquids, contaminated oils, and dry active wastes. Recent tests have demonstrated that it can also incinerate spent demineralizer resins. The system uses a fluidized-bed dryer to process liquid wastes and a separate fluidized-bed incinerator for dry wastes. The final waste products are a granular solid and a fine powdered ash, respectively. The VR factor varies with the material being processed; however, it should range between 25 and 35 after solidification of the final product.

The second leading technology, WasteChem's bitumen solidification system, is designed to process wet wastes, including liquid concentrates and spent demineralizer resins. It features a dual-screw extruder-evaporator. In this process hot bitumen is intimately mixed with the waste. The reduction in volume is achieved by evaporating the water in the waste material. The discharged waste-bitumen mixture solidifies as the thermoplastic bitumen is allowed to cool in a disposal container. The VR factor for this unit should range from 2 to 5. (Because the unit essentially acts as a dryer, its VR factor is much lower than that of an incinerator process.)

Currently, EPRI is documenting the installation and initial operation of the lead systems of the Aerojet Energy Conversion and WasteChem technologies. The information collected should be very useful to utilities in planning radwaste VR additions. It will also be valuable in optimizing system installation and defining operating characteristics.

The first advanced VR system to become operational at a U.S. nuclear power plant is the WasteChem bitumen solidification unit at Consumers Power Co.'s Palisades station. Startup testing of the unit, a retrofit to the plant radwaste system, began in late 1982. During the startup and acceptance test program, the unit processed nonradioactive simulated wastes that represented the three major waste streams: concentrated boric acid, bead demineralizer resin, and powdered demineralizer resin. Operating data and information on the retrofit installation are now being assembled for publication.

An Aerojet Energy Conversion incinerator-dryer at Commonwealth Edison Co.'s Byron station is expected to be the first such unit in operation. System installation is in the final stage, and preoperational testing is scheduled for later this year. A report on the installation, testing, and initial operation of the system will be issued.

Minimization of waste generation

As noted above, utilities are under increasing economic and regulatory pressure to minimize waste disposal volumes. Many have committed to advanced radwaste VR additions. With or without such additions, it is cost-effective to minimize the volume of waste generated by plant operations. To aid in this area, EPRI initiated a project to identify radwaste sources and reduction techniques (RP1557-3).

The project focused on establishing a reliable data base on various LLW categories for nuclear plants with different design features. Detailed information was gathered from two-thirds of the nuclear units in commercial operation in the United States. The data cover plant design and operating characteristics as well as waste volumes by source. This has enabled an in-depth analysis of waste generation experience that takes into account various nuclear plant features. Table 1 presents annual LLW volumes shipped (by waste category) for the typical BWR and PWR.

Analysis of the data has provided a wealth of information on waste generation and the operating factors that influence it. It was found, for example, that BWRs initiating condensate demineralizer resin throwaway operation reduced their wet waste volume by approximately 40%. Also, PWRs able to convert from concentrator to demineralizer processing of wet waste have reduced this source by as much as 75%.

The project also sought to identify waste reduction techniques that have been successfully implemented at nuclear stations. Each technique was carefully defined, and, if possible, its effect on volume was quantified. Over 100 such techniques were documented. It was most encouraging to note that many plants have successfully instituted dry waste minimization programs, with reductions in the range of 20–60%.

Table 1
TYPICAL VOLUMES OF LOW-LEVEL WASTE SHIPPED
(ft^3/yr)

Waste Type	PWR	BWR
Dry waste		
Compactable	4,800	14,300
Noncompactable	5,500	8,050
Filters	250	50
Subtotal	10,550	22,400
Wet waste		
Resins	1,050	2,100
Sludge	0	5,550
Concentrates	4,000	4,600
Subtotal	5,050	12,250
Total	15,600	34,650

LLW disposal economics

Economic evaluations of advanced VR systems require complex analyses. Each system has unique design features, and many systems are tailored to specific waste streams. Adding to the complexity, burial pricing has recently shifted from a simple cost per unit volume to a cost structure that includes a waste curie charge.

VR economic evaluations are being addressed in work to develop long-range radwaste disposal strategies (RP1557-11, -12, -13). Ten VR and on-site storage options are being considered in this study. Costs are being calculated for installed equipment in new or retrofitted structures. Operating and maintenance costs for each option are being determined for typical BWR and PWR waste throughputs. In the basic analysis, costs for nearly 3000 combinations of reactor type, VR equipment, storage options, shipping distances, and burial site characteristics are being calculated and analyzed. This study is designed to help a utility determine the VR options best suited to its circumstances. *Project Manager: Michael Naughton*

SEVERE ACCIDENT ANALYSIS

After Three Mile Island the nuclear industry examined hypothetical severe accidents beyond the design basis for nuclear power plants. A realistic assessment of the risks posed both to the public and to the plant owner by postulated severe (degraded core) accidents requires a best-estimate methodology for analyzing accident progression. EPRI's recent efforts—in direct support of the industry degraded core rule-making (IDCOR) program—were to develop models for the initial core heat-up and degradation phase of a postulated severe accident. In this phase of the accident scenario, a large fraction of the hydrogen from oxidation of the fuel element cladding and volatile fission products from the fuel are released to the coolant system. Hydrogen combustion may cause containment pressure to increase, thus potentially challenging containment integrity; release of the fission products to the atmosphere is the major potential hazard to public health and safety.

As part of its work for the IDCOR program, EPRI has developed computer codes to model both PWR and BWR core heat-up and the release of volatile fission products and core material from an overheated reactor core. These computer codes and models have been developed for incorporation into the IDCOR severe accident analysis codes, MAAP and RETAIN. MAAP predicts pressure and temperature in the containment during a postulated degraded core accident; RETAIN predicts the retention of the fission products in the primary system and the containment during their transport.

A general description of the BWR core heat-up code is provided below. The PWR core heat-up code is similar in concept and somewhat simpler in its geometric detail because the PWR core has a relatively uniform and open lattice of fuel rods.

Core heat-up

The core heat-up phase starts with initial uncovering of the core, resulting from a sustained loss of coolant inventory. The initial heat-up rate depends on the thermal-hydraulic conditions in the reactor pressure vessel and the decay heat rate. Briefly, the power-coolant mismatch leads to a progressive core uncovering and a steady increase in the temperature of the fuel rods. When the fuel rod temperature reaches about 1000 K, the Zircaloy cladding weakens and can begin to deform; failure of the fuel rod cladding is expected as temperatures exceed 1000 K. As the temperature reaches about 1300 K, Zircaloy oxidation begins to become significant, along with its attendant large exothermic energy release and production of hydrogen. This process accelerates the rise in local fuel rod temperature to the point where fission product release and core material volatilization can occur. Eventually core melt (or liquefaction) temperatures are reached, and core collapse (slumping) and movement out of the original core boundaries can occur.

The most important products of the core heat-up phase are hydrogen, which is released to the primary system and containment; energy, which is contained in the core as it melts and begins significant slumping; and fission product and core materials, which are released to the primary system and containment.

The BWR core heat-up code

The BWR core heat-up code is designed to calculate the core conditions during the uncovering and heat-up phase for an intact BWR core geometry. The core heat-up model includes the reactor pressure vessel wall, the core shroud, fuel bundles, control blades, and bypass region within the core. The model represents a 732-bundle BWR/6 in a 238-in-diam (6-m) pressure vessel. BWR cores of different size can be accommodated by minor code modifications. The fuel bundle geometry modeled is the 8 × 8R (reload) fuel with 62 fuel rods and two water rods, which represents the most common BWR/6 core design.

The BWR core heat-up code performs core liquid inventory and energy balance calculations to establish the two-phase liquid level in each fuel bundle and the collapsed liquid level in the bypass region. The code can account for bottom flooding from any water supply source, such as the control rod drive flow and feedwater or safety injection through the recirculation system. This latter mode will provide cooling directly within each fuel bundle as the core is flooded from the bottom. Above the two-phase liquid level, the energy balance in each bundle involves rod-to-steam, rod-to-rod, and rod-to-channel convective and radiative heat transfer, along with Zircaloy oxidation and hydrogen formation. A simple model for core spray cooling has also been formulated and incorporated in the code.

The BWR core heat-up code has been applied to the simulation of a large-break LOCA with assumed failure of all emergency core-cooling systems. The analysis assumed a constant pressure during the boildown of 0.2 MPa (30 psia) with the system initially in thermal equilibrium. Core uncovering was assumed to start at 300 seconds after reactor scram. Figure 2 shows the rate and total mass of hydrogen generated during the core heat-up phase. At 5000 seconds the calculation predicted a total generation of 366 kg (805 lb) of hydrogen. The core water level at that time was calculated to be 0.247 m (9.72 in) above the bottom of the core.

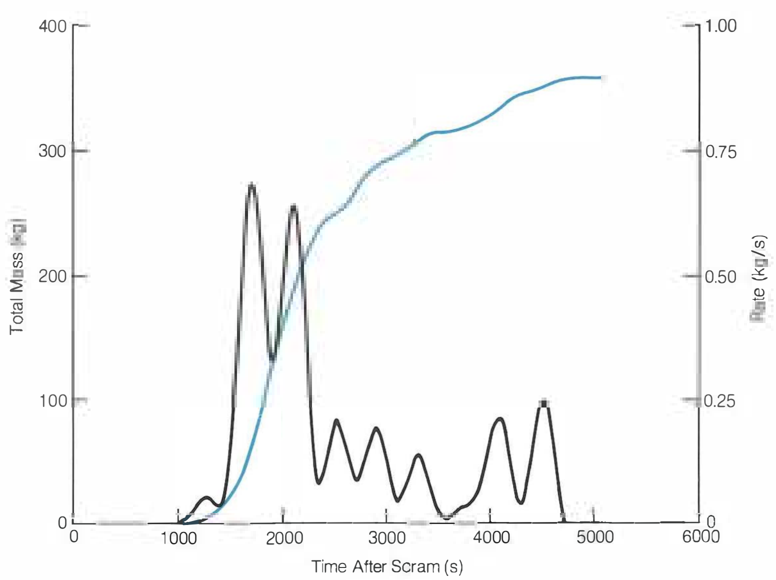


Figure 2 Hydrogen generated (color) and generation rate (black) during heat-up of a BWR core for a postulated large-break LOCA with failure of all emergency core-cooling systems.

Fission product and core material sources

The volatile fission products—xenon, krypton, cesium, iodine, tellurium—and volatile core materials are released from the core during the late portions of the core heat-up phase of the postulated degraded core accident. The rates of release of these fission products and core materials are functions of fuel temperature, core environmental conditions, volatilities of the fission products and core materials, and other parameters, such as the fuel burn-up history and fuel heat-up rate.

There is a very limited set of measurements of the fractional release of some fission products from overheated fuel. These data were analyzed in NUREG 0772, wherein an empirical model was derived for fission product release as a function of fuel temperature. This model does not treat the time dependence of release explicitly and another model was selected for predicting the release of fission products from fuel. This so-called steam-oxidation model gives the dependency of the release on the fuel temperature and the amount of time at temperature, and it provides conservative estimates, compared with the measured releases from available experiments.

The vaporized fission products enter the gas (steam and hydrogen) stream, mix, and rapidly react chemically together and with the core materials at the prevalent high temperatures. The resulting chemical compounds and species are determined from an equilibrium-thermodynamics analysis in which the Gibbs energy of the mixture is minimized. A large number of chemical compounds are identified and their relative concentrations in the flowing gas are determined as a function of the gas temperature, pressure, and composition. Both vaporization and condensation regimes are considered, and the vapor pressures of various chemical compounds are determined. The calculations show that for the iodine species the predominant chemical form is cesium iodide; for the cesium species, it is cesium hydroxide; for the tellurium species, it is hydrogen telluride.

The fission product and core material vapors are transported by the flowing gas mixture of steam and hydrogen. The rate of transport is determined by the gas mass flow rate and the concentration of the vapor of

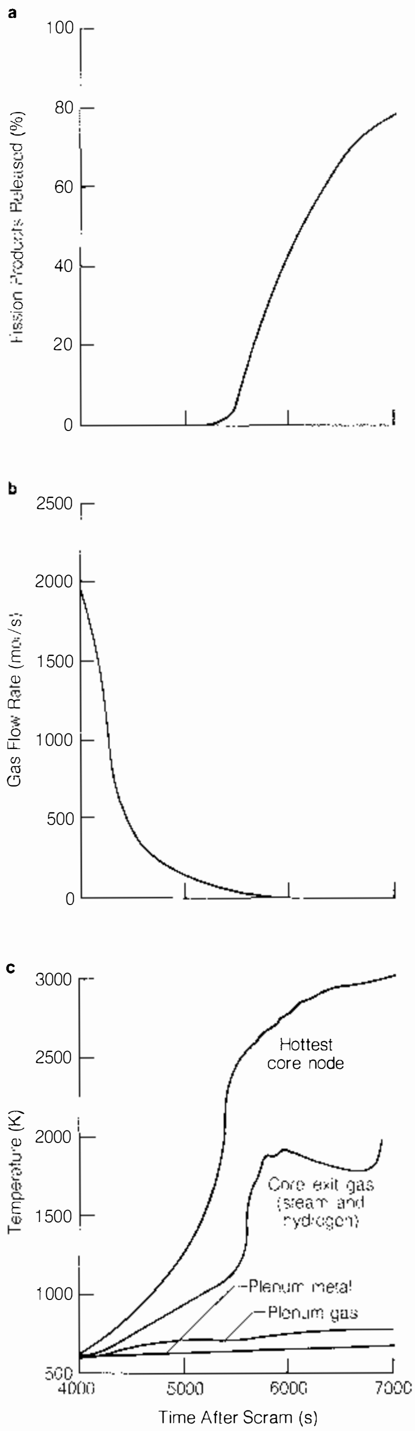


Figure 3 PWR core heat-up code and fission product release model for the TMLB′ postulated accident: (**a**) percentage of the volatile fission product inventory released from the fuel; (**b**) gas flow rate from the core; (**c**) temperatures of the hottest core node, core exit gas, plenum gas, and plenum metal.

the individual species at the prevailing temperature of the gas. The concentration of an individual species is assumed not to exceed the saturation concentration at the gas temperature and any excess material remains in the core. The concentration of the fission products is low and, in general, below the saturation level.

The vapors transported through the core encounter lower temperatures near the top of the core and condense on the relatively colder surfaces. Whatever vapors escape condensation at the exit from the top of the core condense when the mixing of the gas streams from the various rod bundles occurs in the lower region of the upper plenum. The condensation and aerosolization of the fission product and core materials in each channel of the core and in the mixing zone above the core have been considered. Of the various aerosolization processes considered, it was found that homogeneous and heterogeneous condensation resulting in droplet formation will predominate.

Methodology application

The methodology described above for the fission product and vaporized core material release and transport through the core regions have been incorporated in a computer code called FPRAT (fission product release and transport) designed for use in conjunction with a core heat-up code. Some illustrative calculations were performed for a postulated TMLB′ accident in a PWR (transient with loss of cooling water and failure of all ac power). The temperatures, flow rates, and the hydrogen-steam mass fractions in a number of core regions and the upper plenum were calculated with the PWR core heat-up code. Figure 3 shows the temperatures of the hottest core node, the core exit gas (steam and hydrogen), the plenum gas, and the plenum metal as a function of time after reactor scram. The very high rate of temperature increase that occurs when Zircaloy oxidation becomes active is seen clearly at ~5400 seconds (1.5 hours). The plenum gas temperature is much lower than that at the exit of the core because of its interaction with the large mass of the plenum structure. The variations of gas mass flow rate and the cumulative release of the fission product inventory from the fuel are also shown in Figure 3. The figure shows that in the TMLB′ transient the gas flow rate drops to very low values near the time when a large amount of fission products are being released from the fuel.

The information obtained from the PWR core heat-up code was used to calculate the source of the iodine compounds (primarily CsI) at the top of the core. Figure 4 shows

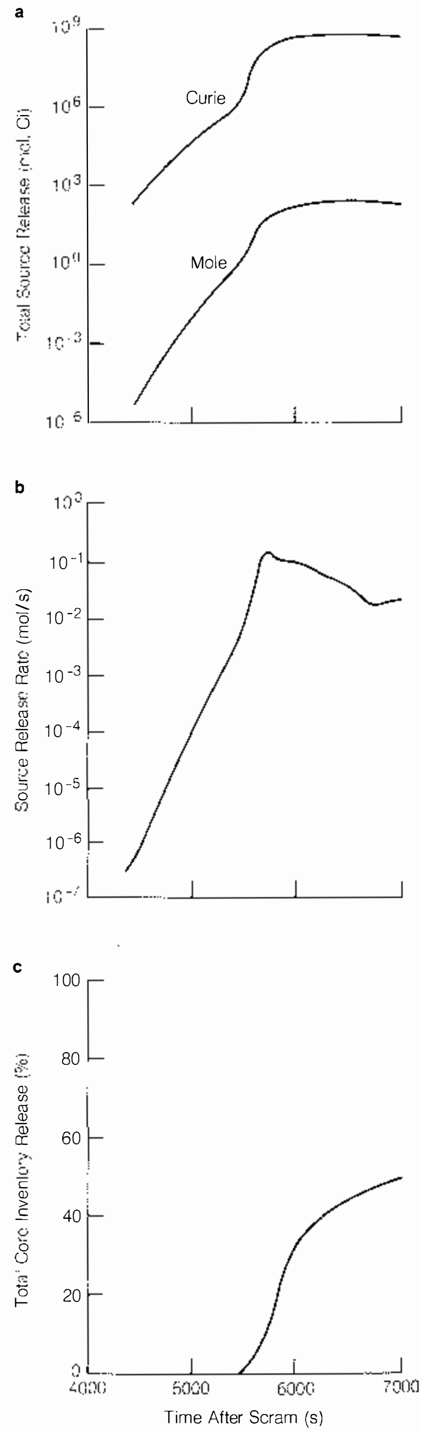


Figure 4 Source of volatile fission product iodine released over time in the postulated TMLB′ accident: (**a**) total source release; (**b**) source release rate; (**c**) total percentage release of the core inventory.

the results obtained in terms of the moles and curies, the rate of vaporization, and the percentage of the total inventory of the iodine compounds vaporized. It is seen that for this example about 60% of the total iodine inventory ($\simeq$100 moles) may be released. It was found that the saturation partial pressure in the plenum is several orders of magnitude less than the partial pressure at the top of the core and there is every likelihood of the iodine-compound vapors condensing in the plenum region either as aerosols or as deposits on cold surfaces of the upper plenum and upper head structures.

Estimates of the sources of various fission products and core materials at the top core boundary were made for two postulated PWR accident sequences, which represent a broad range of potential accident conditions. For the postulated TMLB′ accident, it is estimated that a total of approximately 350 kg of fission products and core materials could be available at the top core boundary. This source could be released in a span of from 30 to 50 minutes. The major part of the source comprised equal amounts of cesium compounds (CsOH) and indium, while iodine compounds (CsI), tellurium compounds, cadmium, and manganese constituted most of the rest. For the postulated AD accident (large-break LOCA with failure of the emergency core-cooling system), about 420 kg were estimated to be vapor-transported to the top of the core. Of that, about 140 kg were indium, 160 kg were cesium compounds, and the rest were iodine and tellurium compounds, cadmium, iron, and tin. It is believed that these source estimates are conservative, not only because of the conservatism incorporated in the models but also because the temperatures calculated to be sustained in the intact core are artificially high. It should be emphasized that these calculations are only examples to show the applications of the methodology.

The work performed so far on the thermal and hydraulic conditions in the plenum and upper head regions of the reactor vessel indicates that the gas and metal temperatures prevalent there may be less than 900 K (Figure 3). There are strong thermal gradients present and the flow patterns may be of the recirculatory type because of strong natural convection forces. There may also be substantial residence times for the aerosols and vapors when the relief and safety valves are closed during the postulated TMLB′ accident. Thus, the environment is conducive to aerosol droplet agglomeration and gravitational settling and to plate-out on the cold surfaces of the plenum because of thermophoresis and impaction.

Research results

Three computer programs—the PWR core heat-up code, the BWR core heat-up code and FPRAT (fission product release and transport)—have been completed. The first two predict the temperatures, the gas (steam plus hydrogen) flow rates, and the hydrogen molar fractions in the core region during the course of the postulated accidents. The hydrogen release rate as a function of time is calculated in the PWR and BWR core heat-up codes. The modeling accounts for the observed reduction in the Zircaloy oxidation rate with the increase in the hydrogen molar fraction of the gas flowing past the cladding. The FPRAT code employs these predicted conditions to estimate the sources of the various volatile fission product compounds (e.g., CsI, CsOH) and the core materials (e.g., Sn, Mn, Cd) appearing at the top of the core, as a function of time, during the accident. These codes contribute toward a best-estimate methodology for evaluating the consequences of postulated severe accidents in LWR nuclear power plants. The results obtained and reported here indicate that the fission product and hydrogen sources are smaller than calculated by computer codes previously used. *Project Managers: John Carey and B. R. Sehgal*

New Contracts

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
Advanced Power Systems				
RP832-14	Screening Studies of Two-Stage Coal Liquefaction	5 months	50.6	Hydrocarbon Research, Inc. *N. Hertz*
RP1525-3	Crystallizer Test Program	7 months	165.6	The Ben Holt Co. *J. Jackson*
RP1996-5	Wind Turbine Test Engineering	1 year	195.9	Rockwell International Corp. *F. Goodman*
RP1996-11	Technical Services for Wind Turbine Research	1 year	186.3	Burns & McDonnell Engineering Co. *F. Goodman*
RP2466-1	Test Facility Support for the Study of Current Consolidation for MHD Generators	6 months	134.9	Mountain States Energy, Inc. *L. Angello*
RP2469-1	Development of Low-Rank Coal–Liquid CO_2 Slurries	6 months	134.8	Arthur D. Little, Inc. *J. McDaniel*
RP2470-1	Thermal Dewatering of Low-Rank Coal for Concentrated Water Slurries	11 months	158.3	University of North Dakota *G. Quentin*
Coal Combustion Systems				
RP982-32	FGD Information System	8 months	81.7	Pedco Environmental Specialists, Inc. *C. Dene*
RP1184-3	Turbine and Superheater Bypass System Evaluation	17 months	257.7	Power Dynamics, Inc. *F. Wong*
RP1338-8	State-of-the-Art Magnetite Recovery by Magnetic Separation	5 months	58.9	Eriez Magnetics, Inc. *R. Row*
RP1835-5	Engineering Assessment: Electrostatic Precipitators With Wide Plate Spacing	17 months	498.8	Combustion Engineering, Inc. *R. Altman*
RP1895-12	Influence of Coal Particle Size on Coal-Water Slurry Combustion	5 months	75.4	Energy and Environmental Research Corp. *R. Manfred*
RP2300-3	Dechlorination Technology Manual	9 months	110.9	Sargent & Lundy Engineers *M. Miller*
Electrical Systems				
RP246-4	Computer Program: Calculation of Upstream Flow Field of Asymmetric Dual-Flow Interrupters	23 months	98.1	Research Polytechnic Institute *N. Hingorani*
RP1507-3	Development of an HVDC Breaker	13 months	500.0	Brown Boveri Corp. *J. Porter*
RP2439-1	Long-Life Cable Development: Cable Material Survey	9 months	94.4	University of Connecticut *B. Bernstein*
RP2443-1	Development of a 10-kV Light-Triggered Thyristor With Built-In Protection	22 months	547.6	General Electric Co. *H. Mehta*
RP7890-5	Uniwema 400 Property/ Facility Management	1 year	54.4	The Bridgeport Interest, Inc. *T. Rodenbaugh*
RP7890-6	Bridgeport Facility Management Transfer and Inspection	33 months	37.6	Seymour Cambias, Jr. *T. Rodenbaugh*
Energy Analysis and Environment				
RP799-19	Comparison of Electric Field Exposure Monitoring Instrumentation	11 months	53.3	T. Dan Bracken, Inc. *R. Kavet*
RP942-5	Model: In-Plant Generation Forecasting	16 months	198.2	Mathtech, Inc. *E. Beardsworth*
RP1781-3	Strategic Planning Methods	10 months	150.0	Applied Decision Analysis, Inc. *S. Mukherjee*
RP1781-4	Long-Range Planning Support	19 months	29.8	Strategic Decision Group *S. Peck*
RP1820-4	Load Data Pool Feasibility	6 months	89.1	Synergic Resources Corp. *E. Beardsworth*
RP1946-4	Transfer Support for the Air Emissions Risk Assessment Model	5 months	30.0	Mindware *D. Fromholzer*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1954-3	Population Exposure to SO_2 and Particulate Matter Risk Estimates; Phase 2	31 months	442.8	Roth Associates, Inc. *R. Wyzga*
RP2152-2	Cost-Effectiveness of Utility Demand Management Programs for the Commercial Sector	20 months	396.8	Temple, Barker & Sloane, Inc. *J. Wharton*
RP2194-1	Strategies for Coping With Drought	2 months	122.3	University of Washington *E. Altouney*
RP2199-1	Receptor Modeling for Apportioning Sources to Air and Precipitation Quality	31 months	160.8	SRI International *J. Guertin*
RP2199-2	Receptor Modeling for Apportioning Sources to Air and Precipitation Quality	17 months	139.5	Desert Research Institute *J. Guertin*
RP2262-1	Data Center for Environmental Physics and Chemistry	17 months	237.1	Systems Applications, Inc. *R. Patterson*
RP2333-1	Global CO_2 Sources and Sinks	31 months	595.8	University of California *G. Hilst*
RP2342-2	Experimental Design: Athens Integrated Load Control	10 months	60.6	Energy & Control Consultants, Inc. *J. Chamberlin*
RP2391-1	Multicontract Pricing Models for Electric Power	7 months	30.0	Pricing Strategy Associates *H. Chao*
RP2434-1	Data Collection for MATEX Feasibility Study	6 months	70.0	National Oceanic and Atmospheric Administration *R. Patterson*

Energy Management and Utilization

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP226-7	Thin-Sheet Graphite	11 months	57.2	Airco, Inc. *D. Douglas*
RP1201-30	EUCT Program Planning and Evaluation Assistance	20 months	69.5	Bevilacqua-Knight, Inc. *T. Schneider*
RP1276-20	Cogeneration Technology Data Base for DEUS Computer Evaluation Model	7 months	59.5	RMR Associates *S. Hu*
RP2038-4	Comparative Evaluation: Acoustic Flow Measurement System	18 months	109.0	Tennessee Valley Authority *C. Sullivan*

Nuclear Power

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1165-2	Cable Tray Fire Protection	10 months	85.0	EDS Nuclear, Inc. *J. Matte*
RP1250-5	Zircaloy Waterside Corrosion at Extended Burnup	6 months	83.8	Exxon Nuclear Co., Inc. *A. Machiels*
RP1584-3	Heat Transfer Coefficient and Friction Factor Correlations	6 months	65.0	EDS Nuclear, Inc. *G. Lellouche*
RP1930-8	BWR Hydrogen Water Chemistry; Radiological Monitoring	14 months	126.7	Advanced Processs Technology *M. Naughton*
RP1939-2	Technology Transfer: Main Steam Isolation Valve Seat Honing Tool	6 months	66.0	J. A. Jones Applied Research Co. *B. Brooks*
RP2061-9	Verification of SPEAR–BETA Fuel Reliability Predictions	7 months	31.7	Entropy Limited *D. Franklin*
RP2121-2	Analysis of In-Pile Heat Transfer Tests Under Accident Conditions	10 months	56.2	Atomic Energy Research Establishment *M. Merilo*
RP2167-2	Enhancing Plant Effectiveness by Improving Organizational Communication	23 months	250.0	Bio Technology, Inc. *H. Parris*
RP2186-4	In-Situ Application of Hardfacing in Main Steam Isolation Valves	7 months	48.8	J. A. Jones Applied Research Co. *B. Brooks*
RP2230-2	Nuclear Plant Feedwater Heater Handbook	11 months	142.9	Heat Exchanger Systems *N. Hirota*
RP2232-3	Automated Nuclear Power Plant Maintenance	2 months	56.5	Advanced Resource Development Corp. *T. Law*
RP2295-2	PWR Water Chemistry Loop Studies	2 years	400.0	AERE Harwell *C. Wood*
RP2348-3	Identification of System Interaction for Licensing and Safety	5 months	52.8	EDS Nuclear, Inc. *B. Chu*
RP2349-1	Simplified Pipe Testing System	20 months	386.0	Robert L. Cloud Associates, Inc. *G. Sliter*
RP2405-1	Demonstration of Linear Holography for IGSCC Sizing	6 months	33.7	Amdata Systems, Inc. *J. Quinn*

Planning and Evaluation

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2345-12	Transmission Line Siting Constraints	4 months	39.5	EDAW, Inc. *S. Feher*

R&D Staff

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP2258-3	Effect of Dynamic Strain on Crack Tip Chemistry	19 months	128.0	Southwest Research Institute *B. Syrett*
RP2260-3	Corrosion of Ceramics and Refractories in Utility Environments	18 months	100.0	SRI International *W. Bakker*

New Technical Reports

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

Inquiries on technical content may be directed to the EPRI project manager named at the end of each 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. Overseas price is double the listed price. Research Reports Center will send a catalog of all EPRI reports on request. Microfiche copies are also available from Research Reports Center, at the address given above. The price per volume of $6.00 in the United States, Canada, and Mexico and $12.00 per volume overseas includes first-class postage.

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ADVANCED POWER SYSTEMS

High-Temperature Ceramic Heat Exchanger Development

AP-3019 Final Report (RP545-2); $17.50

Testing was conducted as part of an effort to develop the technology required for a high-temperature, high-pressure ceramic heat exchanger. The tasks included (1) the extension of a ceramic materials data base to include stress rupture and static fatigue tests at 1250°C, (2) development of ceramic-ceramic and ceramic-metal mechanical seals between heat exchanger manifold modules and manifolds and external ducts, and (3) testing of a subscale module under full design conditions for both pressure and temperature. The contractor is AiResearch Manufacturing Co. of California. *EPRI Project Manager: W. T. Bakker*

Economic Assessment of the Impact of Plant Size on Coal Gasification–Combined-Cycle Plants

AP-3084 Final Report (RP2162-01); $16.00

This screening study evaluates how varying the capacity of coal gasification–combined-cycle power plants affects plant performance, capital cost, and electricity cost. Five cases are addressed, covering nominal capacities of 1000, 500, 250, 100, and 50 MW. Each case is based on the Texaco coal gasification process and Illinois No. 6 coal. The contractor is Fluor Engineers, Inc. *EPRI Project Managers: M. J. Gluckman and A. E. Lewis*

State-of-the-Art Survey of Wood Gasification Technology

AP-3101 Final Report (RP986-9); $17.50

This report summarizes the state of the art of using low-Btu gas produced from wood as a substitute for oil or natural gas in existing small utility boilers (2–50 MW). It discusses domestic and foreign manufacturers of wood gasifiers; wood resource availability; models and methods for estimating wood residues and biomass crop yields on an annual basis; and wood gas economics. The contractor is Fred C. Hart Associates, Inc. *EPRI Project Manager: S. M. Kohan*

Improved Operability of Advanced Gasification-Based Power Plants: Research Planning Assessment

AP-3103 Final Report (RP1654-10); $10.00

A survey of operation and control methodology was conducted to identify potential ways to improve the reliability and performance of future commercial gasification–combined-cycle power plants. This report describes promising R&D projects for operability improvement that involve plant operational analyses, coordinated control methods, and training simulator development. The requirements of these projects are discussed, and a project management plan is presented. The contractor is Systems Control, Inc. *EPRI Project Manager: G. H. Quentin*

Advanced Cooled Combustor Development

AP-3104 Final Report (RP1319-7); $19.00

As part of work to apply advanced cooling techniques to utility combustors, this project investigated the use of Lamilloy (developed by General Motors Corp.) to improve component reliability and durability. A combustor with a Lamilloy liner was designed, built, and tested. Its major advantages, including an improved exit-temperature pattern factor, are discussed. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: Arthur Cohn*

Proceedings of the Second Annual EPRI Contractors' Conference on Coal Gasification

AP-3121 Proceedings (WS82-11); $41.50

This report contains the technical papers presented at the Second Annual EPRI Contractors' Conference on Coal Gasification, held in October 1982 in Palo Alto, California. The sessions covered economics, test results from large pilot plants, progress reports on demonstration projects, modeling and simulation studies, bench-scale investigations, and environmental control and monitoring. *EPRI Project Managers: Neville Holt and George Quentin*

COAL COMBUSTION SYSTEMS

Coal Waste Artificial Reef Program: Conscience Bay Studies

CS-3071 Topical Report (RP1341-1); $25.00

This report describes earlier studies (1977–1981) that culminated in the successful placement of 15,000 coal waste blocks in the Atlantic Ocean off Long Island, New York. This research was conducted to assess the technical feasibility and environmental acceptability of the ocean disposal of coal wastes. It focused on the strength of the materials, chemical properties and behavior, and biological considerations. The contractor is Marine Sciences Research Center. *EPRI Project Manager: D. M. Golden*

Design and Operation of a Light-Scattering Device for Sizing and Velocimetry of Large Droplets

CS-3098 Interim Report (RP1260-11); $16.00

This report documents the development of a light-scattering device for measuring the size and velocity of large droplets. The device was custom-designed for use as a laboratory-standard instrument in a comparative evaluation of alternative cooling-tower drift measurement methods. A thorough discussion of the theory of light scattering by large water droplets is included, and instrument calibration procedures are described. The contractor is the Massachusetts Institute of Technology. *EPRI Project Manager: J. A. Bartz*

ELECTRICAL SYSTEMS

Hierarchical Power Control Center Analyzer

EL-2835 Final Report (RP1047-1); Vol. 1, $17.50; Vol. 2, $13.00; Vol. 3, $25.00; Vol. 4, $16.00

This report describes the development of the Hierarchical Power Control Center Analyzer. Volume 1, the technical manual, presents guidelines for applying the performance and cost analyzers in modeling control centers. Volume 2 is a user's manual and Volume 3 a programmer's manual. Volume 4 contains appendixes and a bibliography that provide technical data augmenting the first three volumes. The contractor is Computer Sciences Corp. *EPRI Project Manager: C. J. Frank*

Global Error Analysis for Application of the Trapezoidal Rule to Systems With Nearly Periodic Components

EL-3088 Final Report (RP670-2); $14.50

This report presents a practical and accurate method of global error estimation for problems with large oscillatory components. This method is directly applicable to transient stability. The report includes a thorough investigation of several classical global error estimation methods as they apply to the mixed differential and algebraic systems found in transient stability analysis. The contractor is Boeing Computer Services, Inc. *EPRI Project Manager: J. W. Lamont*

Software Development and Maintenance Guidelines

EL-3089 Topical Report (RP1714-1), Vol. 1; $46.00

This volume contains a set of guidelines for the development and maintenance of software. Overall procedural and documentation guidelines are provided, as well as guidelines for each stage in the software life-cycle process. The contractor is Science Applications, Inc. *EPRI Project Manager: J. W. Lamont*

Substation Grounding Scale-Model Tests

EL-3099 Interim Report (RP1494-3); $16.00

This report discusses the design of energized scale models of HVAC station grounding grids in an electrolytic tank. The measured resistance of the grid to remote earth is analyzed, and graphic plots of the surface potential under fault conditions are provided. The scale-model results are compared with results from three computer programs. The contractor is Ohio State University. *EPRI Project Manager: J. H. Dunlap*

High-Capacity Single-Pressure SF_6 Interrupters

EL-3100 Final Report (RP478); $22.00

This report describes the design, development, and construction of a prototype high-voltage single-pressure SF_6 interrupter with a dual goal of 120 kA at 145 kV or 100 kA at 242 kV with a continuous current rating of 5000 A. Details are provided on mathematical models used to extrapolate design requirements from existing data; two model puffer-type interrupters designed and tested for 100-kA data; a construction materials study; and the optimized interrupter design. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: N. G. Hingorani*

Power Line–Induced AC Potential on Natural Gas Pipelines for Complex Right-of-Way Configurations

EL-3106 Final Report (RP742-2); Vol. 1, $29.50; Vol. 2, $34.00; Vol. 3, $10.00

This report addresses complex common corridor coupling problems for overhead electric power transmission lines and buried natural gas pipelines. Volume 1 describes the development of analytic methods for solving such problems and presents field data used in verification efforts. Volume 2 is a handbook for graphic analysis designed for use by field personnel or others without access to a computer. Volume 3 is a user's guide for the PIPELINE computer code. The contractor is Science Applications, Inc. *EPRI Project Manager: J. H. Dunlap*

ENERGY ANALYSIS AND ENVIRONMENT

Overview, Results, and Conclusions for the EPRI Plume Model Validation and Development Project: Plains Site

EA-3074 Final Report (RP1616-1); $20.50

This report presents an overview of an EPRI project designed to provide data bases and analyses for rigorous operational and diagnostic validation of plume models. The report also summarizes results and conclusions from the first set of field measurements (spring and summer 1980, spring 1981). Procedures for testing plume model performance are outlined, and recommendations for model improvement and development are included. The contractor is TRC–Environmental Consultants, Inc. *EPRI Project Manager: G. R. Hilst*

Dry-Deposition Field Studies

EA-3096 Final Report (RP1630-26); $14.50

This report discusses the field testing and analysis of novel dry-deposition measurement techniques in conjunction with a 1982 EPA experiment. Detailed, high-quality data obtained from the study are presented. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: R. M. Patterson*

Particle Formation and Growth in Power Plant Plumes

EA-3105 Final Report (RP330-1); Vol. 1, $13.00; Vol. 2, $13.00

Volume 1 of this report describes parallel field and theoretical studies of particle-size distributions in the plumes of coal-fired power plants. Volume 2 presents measurements of concentrations of particulate sulfur, sulfate, nitrate, total particulate volume, Aitken nuclei, and various trace gases in the plumes of six coal-fired power plants. The contractor is the University of Washington. *EPRI Project Manager: Charles Hakkarinen*

Controlled Studies of Human Health Effects of Short-Term Inhalation of Atmospheric Pollutants

EA-3125 Final Report (RP1225-1); $13.00

This report presents the results of three years of research into the effects of inhaled air pollutants on human volunteers. The pollutants studied include ammonium nitrate aerosols, mixed SO_2 and NO_2, and sulfate salts of several trace metals (used singly and in combination with gaseous pollutants). In the studies physiological responses during actual exposures were compared with responses during sham exposures. The contractor is the Professional Staff Association of Rancho Los Amigos Hospital, Inc. *EPRI Project Manager: James McCarroll*

ENERGY MANAGEMENT AND UTILIZATION

Monitoring Methodology Handbook for Residential HVAC Systems

EM-3003 Final Report (RP1670-2); $26.50

This report presents a uniform set of guidelines for designing and implementing field-monitoring projects for residential heating, ventilating, and air conditioning (HVAC) systems. The handbook also describes currently available monitoring equipment and data analysis techniques. The contractor is the Berkeley Solar Group. *EPRI Project Manager: J. S. Brushwood*

Turbine Reaction to Free Surface Vortices

EM-3017 Final Report (RP1199-8); $8.50

This report details field work directed at increasing the output and cost-effectiveness of hydroelectric generation by avoiding vortex activity in the upper reservoir intake. To determine the effects of free surface vortex activity, a pump-turbine unit was instrumented to measure mechanical strains and deflections in the machinery train and critical components. The contractor is the Alden Research Laboratory of the Worcester Polytechnic Institute. *EPRI Project Manager: Antonio Ferreira*

Investigation of Layered Structure for Carbonate Fuel Cells

EM-3090 Final Report (RP1085-8); $10.00

This report discusses an evaluation of electrophoretic deposition as a technique for preparing a porous $LiAlO_2$ matrix suitable for use in a molten carbonate fuel cell. Data obtained on electrophoretically deposited and hot-pressed electrolyte structures are compared and contrasted; thermal cycling is similarly treated. The implications of these results for molten carbonate fuel cell design are also discussed. The contractor is General Electric Co. *EPRI Project Manager: A. J. Appleby*

NUCLEAR POWER

LOCA Hydroloads Calculations With Multidimensional Nonlinear Fluid-Structure Interaction

NP-1401 Final Report (RP1065), Vol. 4; $10.00

This volume describes the application of a three-dimensional, nonlinear fluid-structure interaction methodology to the calculation of the structural response of pressure vessel internals during a postulated loss-of-coolant accident. Results of the calculation are compared with test results, and the transient response of the fuel bundle is described. The contractors are Intermountain Technologies, Inc.; Science Applications, Inc.; and Northwestern University. *EPRI Project Manager: R. N. Oehlberg*

Safeguarded Fabrication and Reprocessing (SAFAR): Executive Summary

NP-2631-SY Summary Report; $11.50

This report describes a project to assess the technology requirements of a modern diversion-resistant nuclear fuel reprocessing plant. Design objectives are presented, plant capital costs and operating economics are discussed, and further work required for implementation of the SAFAR concept is outlined. The contractor is Exxon Nuclear Co., Inc. *EPRI Project Manager: R. W. Lambert*

Two-Phase Flow Characteristics During Controlled Oscillation Reflooding of a Hot Vertical Tube

NP-2821 Final Report (RP248-1); $11.50

This report presents the results of experiments performed to determine the transient void fraction in a heated vertical tube under oscillatory inlet flow conditions. Results are discussed for oscillations of various amplitudes and periods superimposed on a constant feed rate. In addition, measurements of temperatures, void fraction, and mass carryover are given. The contractor is the University of California at Berkeley. *EPRI Project Manager: Loren Thompson*

Tube Support Response to Tube Denting Evaluation

NP-2971 Final Report (RPS143-1); Vol. 1, $17.50; Vol. 2, $19.00

This report summarizes a project (1) to provide a basis for analytically predicting steam generator tube support response to tube denting, and (2) to investigate advanced radiography techniques for the nondestructive evaluation (NDE) of support plate degradation. Volume 1 describes the testing of drilled support plates and eggcrate tube supports and evaluates NDE methods for application to operating steam generators. Volume 2 contains the test data. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: J. F. Lang*

Operation of EPRI Nondestructive Evaluation Center: Annual Report, 1982

NP-2985 Interim Report (RP1570-2); $13.00

This report describes a project to design, construct, organize, and operate the EPRI Nondestructive Evaluation (NDE) Center, a dedicated facility for providing field-qualified NDE equipment, procedures, and personnel training to the electric utility industry. The entire scope of the work is reviewed, with major emphasis on the activities in 1982, the facility's first full year of operation. The contractor is J. A. Jones Applied Research Co. *EPRI Project Manager: G. J. Dau*

COMETHE–IIIJ Predictions of Fuel Centerline Temperatures

NP-2992 Final Report (RP971-1); $11.50

Fuel centerline temperature predictions made by the COMETHE–IIIJ computer code are compared with measurements from 18 instrumented fuel rods irradiated in assemblies IFA-431, -432, and -513 at the Halden boiling heavy water reactor. The error characteristics of the code are summarized, and its performance in this test and for predicting fuel temperature in reload licensing submittals is determined. The contractor is Science Applications, Inc. *EPRI Project Manager: S. T. Oldberg*

Evaluation of Steam Generator Fluid Mixing During Layup

NP-2993 Final Report (RPS164-1); $25.00

This report describes a project to develop practical methods of achieving an adequately mixed chemical environment on the secondary side of PWR steam generators during periods of shutdown, cold shutdown (layup), and startup. Systems for chemical feed, mixing, sampling, and removal of contaminant chemicals are evaluated, and recommendations are made. Test results from a Plexiglas model indicate that forced circulation and turbulent mixing are the most effective methods of rapidly achieving a homogeneous chemical environment. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: C. L. Williams*

Deposition of Corrosive Salts From Steam

NP-3002 Final Report (RP1068-1); $19.00

Laboratory tests were performed to determine (1) the solubilities of certain impurities in steam (sodium hydroxide, sodium chloride, and the chloride and sulfate salts of ammonia) below which deposition would not occur under equilibrium conditions, and (2) the level of impurity in dry steam that can be assumed as noncorrosive. Also, a survey was conducted to determine the measured impurities in steam entering low-pressure turbines at typical power plants, and the findings were compared with the test results. The contractor is Babcock & Wilcox Co. *EPRI Project Manager: T. O. Passell*

Microkinetics of Stress Corrosion Cracking in Steam Turbine Disk Alloys

NP-3005 Interim Report (RP1929-8); $11.50

This report documents a study of the feasibility of developing a statistically based model that can predict the likelihood of stress corrosion cracking in low-pressure turbines in representative turbine environments. A preliminary model was developed and used to predict crack nucleation times and growth rates for a single heat of turbine material. The contractor is SRI International. *EPRI Project Manager: A. J. Giannuzzi*

The Studsvik Over-Ramp Project

NP-3007 Final Report (RP1026-1); $17.50

This report presents the results of ramp testing of 39 PWR design fuel rods under fast power increase. Failure thresholds were established within particular groups of rods having nearly identical design and base irradiation history. A useful data set on well-characterized rods is provided for nondestructive and destructive examinations. The data include both steady-state and transient performance characteristics over a significant range of design and operating conditions. The contractor is Studsvik Energiteknik Ab. *EPRI Project Manager: D. G. Franklin*

Chemical Cleaning Demonstration Test No. 2 in a Mock-Up Steam Generator

NP-3008 Topical Report (RPS127-1); $10.00

The results of mock-up demonstration testing of a modified chemical cleaning process for steam generators are presented, and process limitations are identified. The test results indicate that significant process improvements can be obtained by using an ambient-temperature copper solvent and a magnetite solvent with a pH greater than 6. The contractor is Babcock & Wilcox Co. *EPRI Project Manager: C. S. Welty, Jr.*

Steam Generator Chemical Cleaning Process Development

NP-3009 Final Report (RPS150-1); $22.00

This report documents work in connection with the Steam Generator Owners Group program to develop a process for chemically removing iron- and copper-bearing sludges and support plate crevice corrosion product deposits from the secondary side of PWRs. EPRI program guidelines for process performance are included. The contractor is UNC Nuclear Industries, Inc. *EPRI Project Manager: C. S. Welty, Jr.*

Laboratory Program to Examine Effects of Layup Conditions on Pitting of Alloy 600

NP-3012 Final Report (RPS124-1); $10.00

This report documents laboratory screening tests at ambient temperature to determine if certain contaminants could produce pitting similar to that observed in alloy 600 steam generator tubing removed from two operating plants. The tests used a copper chloride solution or seawater and simulated sludge containing copper, copper oxide, and magnetite. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: C. S. Welty, Jr.*

Study of Boiling Processes in the Sludge Deposit of Steam Generators

NP-3018 Final Report (RPS171-1); $16.00

A study was conducted to determine the controlling mechanisms of the boiling processes that occur in steam generator sludge deposits. An analytic model was developed to describe the heat transfer process and dryout extent in terms of thermal parameters and sludge properties and to predict the dryout zone within a porous medium composed of nickel and copper particles. Visualization studies of the effect of rapid vaporization on sludge fluidization were also performed. The contractor is the University of Minnesota. *EPRI Project Manager: D. A. Steininger*

Evaluation of Steam Generator Tube R12C66 From Indian Point No. 3

NP-3029 Final Report (RPS138-6); $11.50

This report documents the detailed examination of a pitted tube from steam generator No. 31 at Indian Point No. 3. Included are the results of inspection by radiography, metallography, scanning electron microscopy, and microchemical analyses of the corrosion product and the surface scale. A review of plant water chemistry data is also given. Plant operation histograms are provided, and recommendations and conclusions are discussed. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: A. R. McIlree*

Tube Support Plate Thermal and Hydraulic Testing

NP-3052 Final Report (RPS180-1); $17.50

A project was undertaken to improve understanding of the relationship between boiling heat transfer, chemical concentration, and particulate deposition in and around tube and tube support plate crevices. Magnetite depostition tests are described, as are thermal and hydraulic tests of various flow distribution baffle and support plate geometries in all-volatile-treatment water and in a sodium phosphate solution. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: D. A. Steininger*

Flushing Efficiency of Steam Generator Tube-Tubesheet Assemblies With Restricted Crevices

NP-3053 Final Report (RPS209-1); $11.50

This report summarizes a project to determine the effectiveness of steam generator tubesheet crevice flushing operations when access to the crevice is restricted by particulate matter within the crevice or by a hard sludge pile on top of the tubesheet. The testing indicates that the most effective flushing procedures are similar to those found to be most effective for unrestricted crevices. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: D. A. Steininger*

Neutralization of Crevice Acids

NP-3054 Final Report (RP623-2); $19.00

Capsule, pot boiler, and model steam generator tests were conducted to develop chemical procedures for limiting dent growth in nuclear steam generators. The testing included off-line isothermal soaks and on-line additions of neutralizers. Nondestructive and destructive examinations were performed after the testing to investigate the mechanisms and side effects of each neutralization procedure. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: J. P. N. Paine*

Stress Relief to Prevent Stress Corrosion in the Transition Region of Expanded Alloy 600 SG Tubing
NP-3055 Final Report (RPS192-3); $10.00

This report examines the induction heating of roller-expanded steam generator (SG) tubing as a means of attaining stress relief. The applicable stress relief heat treatments are outlined; the means of achieving the required temperature-time combination are proposed; and the implication of the stress-relieving process in terms of the tubesheet is considered. The contractor is Brookhaven National Laboratory. *EPRI Project Manager: A. R. McIlree*

In Situ Heat Treatment and Polythionic Acid Testing of Inconel 600 Row 1 Steam Generator U-Bends
NP-3056 Final Report (RPS191-3); $11.50

This report presents an evaluation of an in situ device for heating row 1 U-bends in steam generators in order to produce stress relief and prevent stress corrosion cracking. Tests were conducted to study the uniformity of heating in the U-bend area, microstructural changes resulting from the heat treatment, distortion of the U-bends, and temperature increases in a simulated upper tube support plate. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: A. R. McIlree*

IGSCC of Ni-Cr-Fe Alloy 600 Tubes in PWR Primary Water: Review and Assessment for Model Development
NP-3057 Final Report (RPS138-8); $11.50

This report assesses the current state of knowledge on primary-side intergranular stress corrosion cracking (IGSCC) of alloy 600 tubes and establishes the need for a quantitative model to predict IGSCC. A promising approach to quantitative model development is presented, and the required analytic-experimental work is outlined. Recommendations for collecting steam generator field data are also included. The contractor is S. Levy, Inc. *EPRI Project Manager: A. R. McIlree*

Design and Construction of Deep Tubesheet Crevice Devices for Producing IGA of Heat Transfer Tubing
NP-3058 Final Report (RPS193-2); $11.50

This report describes two tubesheet crevice simulation devices built for the study of intergranular attack (IGA) of steam generator tubing. The units have several design features that make them representative of the tubesheet regions of currently operating steam generators. Thermal and hydraulic data and analyses are presented, and test materials and operations are discussed. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: A. R. McIlree*

IGA of Alloy 600 in High-Temperature Solutions of Sodium Hydroxide Contaminated With Carbonate
NP-3059 Final Report (RPS183-4); $10.00

An electrochemical testing technique was used to study intergranular attack (IGA) of alloy 600. Specimens of the alloy were tested as C-rings under constant deflection, wires under constant load, and wires without any applied tensile stress. The experimental procedure and the results are discussed. The contractor is Brookhaven National Laboratory. *EPRI Project Manager: A. R. McIlree*

Effect of Calcium Hydroxide and Carbonates on IGA and SCC of Alloy 600
NP-3060 Final Report (RPS193-3); $14.50

This report summarizes a series of five tests conducted at a single-tube model boiler facility to determine the influence of alkaline earth carbonates and/or hydroxides on intergranular attack (IGA) or stress corrosion cracking (SCC) of mill-annealed alloy 600. The conditions and time frame of the tests are described, and the results are compared against a reference all-volatile-treatment test condition. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: A. R. McIlree*

Stress Corrosion Cracking of Alloys 600 and 690 in All-Volatile-Treated Water at Elevated Temperatures
NP-3061 Final Report (RPS192-2); $10.00

This report describes a continuing study of stress corrosion cracking of Inconel alloys 600 and 690 in all-volatile-treated water. The materials used, the test specimens, and the test conditions are discussed. Conclusions are presented. The contractor is Babcock & Wilcox Co. *EPRI Project Manager: C. E. Shoemaker*

Intergranular Attack of Alloy 600: High-Temperature Electrochemical Tests
NP-3062 Final Report (RPS193-1); $10.00

This report documents the results of potentiostatic tests on alloy 600 C-rings at 320°C in a 10% caustic medium. The tests were conducted to evaluate the physicochemical parameters that influence intergranular attack. The contractors are Commissariat à l'Energie Atomique and Framatome. *EPRI Project Manager: A. R. McIlree*

Implementation of Boric Acid in the Field: Indian Point Unit 3 Plant
NP-3066 Final Report (RPS116-1); $35.50

This report documents a field test of the use of boric acid to arrest steam generator denting. An on-line hydrogen monitoring technique and inspections were used to determine the baseline condition of the steam generators and to indicate the rate of denting progression. The results reveal that although denting continued, it progressed at a significantly slower rate than in the immediate period before the boric acid treatment. The effect of boric acid on corrosion product transport through the secondary system was also monitored. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: J. P. N. Paine*

Crevice Hideout Return Testing
NP-3067 Final Report (RPS190-1); $10.00

This report describes the progress of a study to develop strategies for promoting the return of hideout contaminants from support plate crevices to the bulk water in operating steam generators. This work examined the use of soaks and flushes with corroded but undented crevices, as well as the effects of the on-line addition of boric acid and calcium hydroxide. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: C. E. Shoemaker*

Evaluation of Critical Flow for Supercritical Steam-Water
NP-3086 Final Report (RP1927-2); $16.00

Experiments were performed on the Winfrith high-pressure rig to obtain subcooled-water critical flow data from four simple geometries over the pressure range of 500–4500 psia. This report presents the results and compares them with predictions by three critical flow models and the Bernoulli equation. Also, high-pressure heat transfer data obtained in the experiments are compared with previously reported work. The contractor is the United Kingdom Atomic Energy Authority. *EPRI Project Manager: L. J. Agee*

SAFER: Stress and Fracture Evaluation of Rotors
NP-3091-CCM Computer Code Manual (RP502-6); $23.50

This report provides the user and programmer guides for the computer code SAFER, which is designed to analyze the typical duty cycle of a steam turbine rotor for transient and steady-state thermal distributions; stress due to thermal, pressure, and centrifugal loads; and fatigue fracture due to flaw growth from repeated cycles. The contractors are Franklin Research Center and American Electric Power Service Corp. *EPRI Project Managers: F. E. Gelhaus and M. J. Kolar*

Experimental Study of Debris Bed Coolability Under Pool Boiling Conditions
NP-3094 Interim Report (RP1931-1); $11.50

This report presents the findings of an experimental investigation into the dryout of a bed of inductively heated particles cooled by an overlying liquid pool. The data are compared with data from other experimental studies and with proposed theoretical models. The contractor is the University of California at Los Angeles. *EPRI Project Manager: David Squarer*

Verification of GFLOW Computer Code
NP-3097 Final Report (RP2240-4); $11.50

This report describes work to validate the GFLOW analytic model as an improved method for performing thermal-hydraulic analysis of spent-fuel storage pools. A comparison of the model's calculations with experimental data from the Maine Yankee spent-fuel storage pool is presented. The contractor is NUS Corp. *EPRI Project Manager: R. W. Lambert*

Investigating the Flux Reduction Option in Reactor Vessel Integrity
NP-3110-SR Special Report; $8.50

This report reviews methods of reducing the fast neutron flux at the reactor pressure vessel wall through alternative fuel management schemes. An assessment of the benefits of such flux reduction schemes in terms of reactor vessel integrity is presented. *EPRI Project Managers: D. G. Franklin and T. U. Marston*

In-Plant Low-Level Radwaste Technology Needs
NP-3117 Final Report (TPS78-825); $13.00

A survey of current low-level radwaste technology was conducted, with emphasis on waste processing and packaging in nuclear power plants. This report discusses the results and proposes a three-part technology improvement program that addresses existing waste generation and treatment systems, alternative technologies, and alternative operation and maintenance practices. The contractor is NUS Corp. *EPRI Project Manager: R. A. Shaw*

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