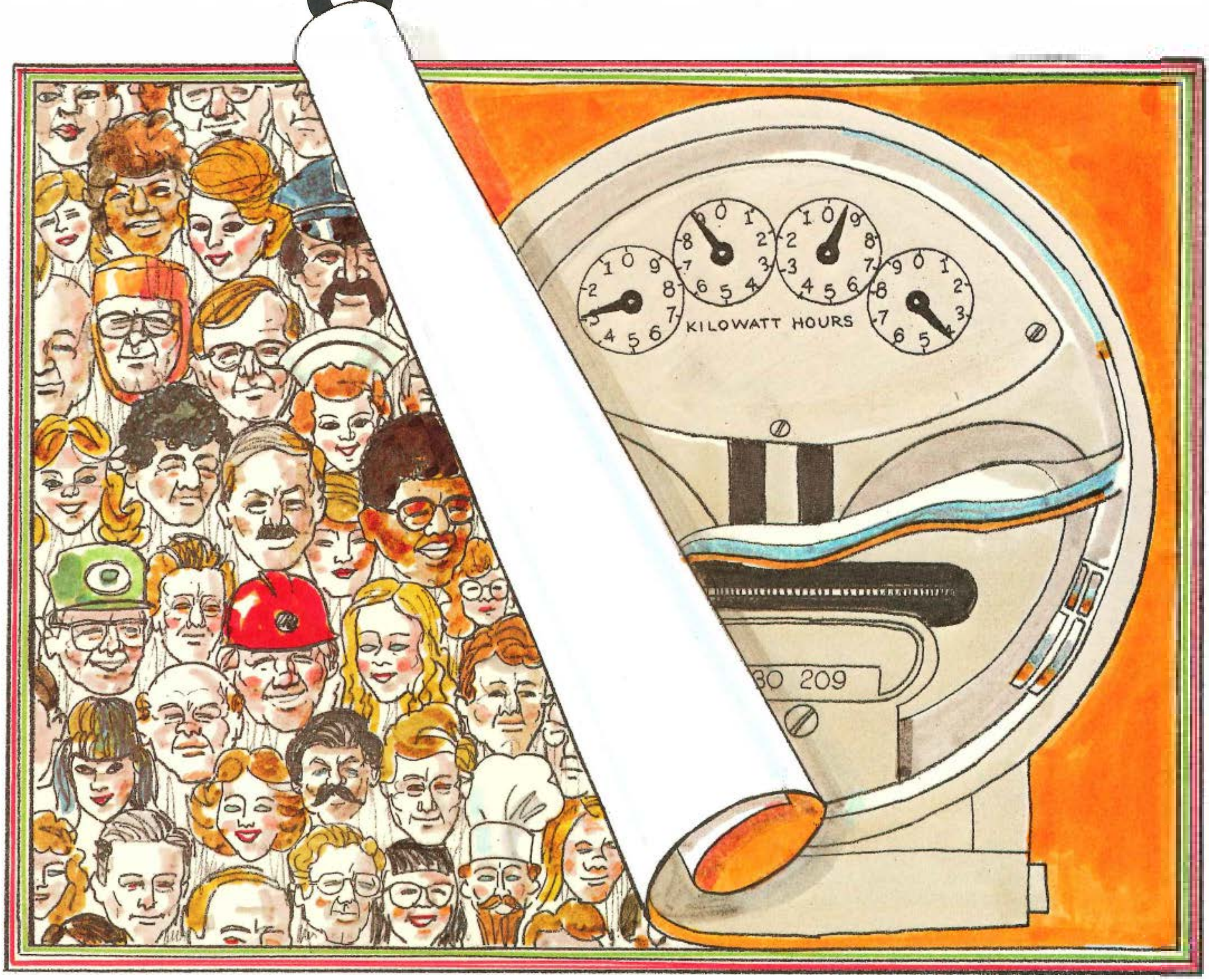
The Customer Behind the Demand

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

DECEMBER
1984



EPRI JOURNAL is published monthly, with the exception of combined issues in January/February and July/August, by the Electric Power Research Institute. The April issue is the EPRI *Annual Report.*

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

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Cover: A new approach to strategic load planning encourages utilities to look beyond the meter and gain a better understanding of how their customers use electricity.

EPRI JOURNAL

Volume 9, Number 10 December 1984

Demand-Side Planning: New Approach to Marketing

Since the electric utility industry began, it has been involved in some form of marketing. In the earlier years marketing meant simply selling. Once markets were opened, they flourished, doubling on average every decade. And in this environment almost any marketing effort produced results. But in the 1970s, with the energy crisis in full bloom, prices rising rapidly, and economies of scale changing, this limited concept of marketing ran head on into conflict with the conservation ethic. Most marketing functions in utilities were disbanded. Conservation programs emerged, as well as many other activities that were closely oriented to customer service.

Now the term is back, but the concept is different. Utility marketing today is much broader, subsuming all the historical options—conservation, load management, and load growth—as the most strategic portfolio for serving the varying needs of highly defined markets. Electricity is being regarded more as a service than as a commodity, and utility marketing has moved more toward the highly individualized concerns of service-based industries. With this has come an enormous need and responsibility to better understand the customer.

It is no longer enough to know how much electricity a customer is using; the utility must also understand when and how it is used. The targets are narrow and the questions are specific: What kind of electric appliance is a certain type of customer using? What type of machine is chosen for a specific industrial process? What incentives would be effective for inducing a business to change the way it uses energy?

Such questions are the starting point for demand-side planning, a sophisticated new process that is developing as an effective and worthy successor to marketing approaches that are no longer in step with how the world views energy. With demand-side planning, the utility's objective is to develop marketing incentives that fit customer preferences and behavior—initiatives that will be of mutual benefit to both the utility and the customer. The answer might be a new type of pricing or rate structure, a promotional program, or low-cost financing for conservation equipment.

One outcome is that utilities will not necessarily be looking for increased sales of electricity. Certainly, utilities that have surplus capacity will be anxious to develop new energy markets. But with the high cost of new capacity construction, it might be in the best interest of utilities with dwindling reserve margins to encourage conservation of energy in certain end uses while selectively encouraging use in others. Utilities with a large differential between base- and peak-load demand would prefer to shift customers' use from the middle of the day to late at night, perhaps by offering incentive rates for off-peak load.

Today utilities are facing renewed competition in the form of alternative energy sources, increased efficiency of competing end-use technologies (such as space heating devices), development of privately owned alternative energy sources, and consumer actions to reduce electricity use. Whether they are looking to build, maintain, or reduce customer loads, utilities will need the better understanding provided by end-use planning. EPRI has exciting work under way to add to its portfolio of planning and forecasting tools. Effective implementation of these tools will not only guide utilities in their marketing plans but will also promote a better understanding of customers, particularly their preferences and behavior in purchasing energy.

Clark W. Gellings, Manager
Demand and Conservation Program
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Authors and Articles

Electricity demand has traditionally been a given quantity in utility planning—that is, its fluctuation was beyond utility purview. Not any more. Because demand has become so difficult for anyone to predict, utilities are trying to exert some influence on it so as to smooth out supply requirements where possible. This month's lead article, **Demand Planning in the '80s** (page 6), reviews the EPRI-sponsored research of economists as they identify and evaluate business approaches that can shape load curves to the mutual benefit of utilities and their customers. Science writer Mary Wayne, who wrote *Forecasting the Patterns of Demand* exactly two years ago, again turned to EPRI's Clark Gellings as her resource.

Gellings has managed the Demand and Conservation Program for the Energy Analysis and Environment Division since May 1982. He was formerly with New Jersey's Public Service Electric & Gas Co. for 14 years, first as a sales engineer, later in applications, and eventually as assistant manager of load management, responsible for assessment of conservation and load management impacts on the utility's demand forecasts. Gellings is a 1968 electrical engineering graduate of New Jersey Institute of Technology, and he added an MS in mechanical engineering there in 1980. In 1975 he was awarded an MS in management science from Stevens Institute of Technology.

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The integrated coal gasification and combined-cycle power generation plant near Barstow, California, is undeniably EPRI's most ambitious technology demonstration to date, an innovative facility all the way from coal to busbar. **Cool Water: Milestone for Clean Coal Technology** (page 16) reviews two major points: early operation, smoother than expected after plant completion ahead of time and under budget; and the capital cost economy that should be possible by staged construction of modular plants like this. John Douglas, the author, is a science writer who visited the plant dedication in October and talked at length with three key EPRI research managers.

Thomas O'Shea has managed EPRI's technical and coordinating role on the Cool Water project since 1978. He came to the Institute a year earlier, after 12 years with Caltex Petroleum Corp., where he became an engineering superintendent during a series of process design and refinery construction assignments abroad. O'Shea is a 1965 electrical engineering graduate of Illinois Institute of Technology.

Harris Gilman, engineering manager for the Advanced Power Systems Division, has worked at the Cool Water plant site since the beginning of 1984 as final subsystems were set in place, connected, and put into operation. Gilman has been with EPRI since 1974, advising on equipment and plant layout for fluidized-bed combustion, coal-oil slurries, and coal liquefaction and gasification projects. He was formerly with Standard Oil Co. of California for 24 years, most of that time with a subsidiary, American Gilsonite Co., in field design, construction, and operations capacities. Gilman graduated from Stanford University in mechanical engineering.

John McDaniel is EPRI's manager for test and evaluation programs now being conducted at the Cool Water plant. Associated with EPRI's Clean Gaseous Fuels Program since 1978, McDaniel was formerly a process design and development engineer for eight years, successively with Northern Petrochemical Co. and Northern Natural Gas Co., both in Omaha. McDaniel is a chemical engineering graduate of the University of Nebraska.

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EPRI's annual Advisory Council seminar focused this year on the subject of cancer risk assessment—rationale and examples, methods and measures. Over a period of three days, the papers and subsequent discussion stimulated by nine speakers were shared by the Council's guests from government and industry. The exchange among some 50 people is interpreted by Brent Barker, the *Journal's* editor-in-chief, in **Cancer and the Problems of Risk Assessment** (page 26).

Barker joined EPRI in June 1977 after four years as a writer and communications consultant. Formerly an industrial economist at SRI International from 1968 to 1973, he was earlier a commercial research analyst with U.S. Steel Corp. Barker graduated from Johns Hopkins University in engineering science; he later earned an MBA at the University of Pittsburgh.

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Until recently, computer simulation of power plant operation required a patchwork of separate models and manual calculations to integrate them. **A Modular Code for Plant Dynamics** (page 36) reviews a newly released EPRI computer code that permits analysis of components and subsystems under normal or transient conditions. The article was written by Taylor Moore, *Journal* feature writer, aided by project managers from two EPRI technical divisions.

Murthy Divakaruni, who came to the Nuclear Power Division in November 1981, manages projects in plant simulation software and digital control systems development. He was formerly with General Electric Co. for five years, much of that time as an energy systems development engineer but eventually as a project engineer for man-machine interface programs in the Advanced Reactor Systems Department. Earlier, he was a propulsion engineer with the Indian Space Research Organization. Divakaruni has a BS in mechanical engineering from the University of Madras and an MS in the same field from the Indian Institute of Technology. He also has an MS in fluid mechanics from the University of Cincinnati and an MBA from Xavier University.

Frank Wong, a project manager in the Coal Combustion Systems Division since August 1982, specializes in plant performance. He was formerly with The Cleveland Electric Illuminating Co. for seven years, a project engineer for programs and methods to improve the availability and reliability of fossil-fuel-fired units. Wong graduated in mechanical engineering from the University of Dayton; he earned an MS in industrial engineering at Cleveland State University.

Gellings

Barker

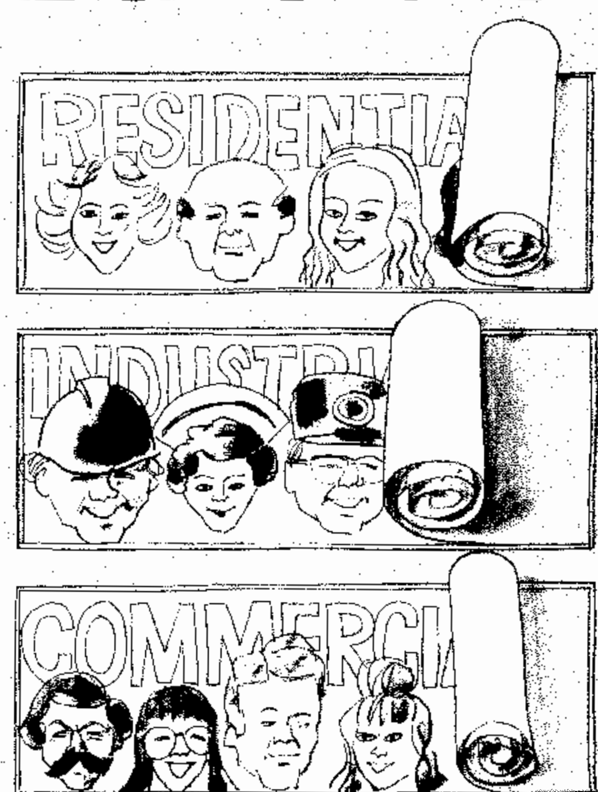
Divakaruni Wong

McDaniel

O'Shea

Gilman

Demand Planning in the '80s



As utilities look beyond the meter to gain a better understanding of customer behavior and preferences in energy use, they are finding new opportunities for shaping future demand.

Future demand for electricity has been treated traditionally as a predetermined quantity by utility planners. Their job has been to estimate that quantity, then plan supply accordingly. But the energy disruptions of the 1970s put a crimp in this familiar process. Predictable demand and flexible low-cost supply, the prerequisites of traditional planning, became harder and harder to achieve.

So the natural questions emerged: Why keep treating demand as fixed? Why not work with demand as well as supply to make a match? The result has been a new utility emphasis on demand-side planning. And actively planning demand is quite different from predicting what demand will be.

About 300 utilities nationwide already run some 1000 separate projects aimed at shaping future demand, although not all are the product of formal planning. Clark Gellings, manager of EPRI's Demand and Conservation Program in the Energy Analysis and Environment Division, estimates that nearly 50% of the nation's utilities are actively engaged in some form of demand-side planning. "The projects," he notes, "are not limited to a particular kind of utility or a particular geographic region. The approach applies equally well to large and small, municipal and investor-owned, urban and rural utilities across the country."

Demand-side planning carefully pinpoints utility actions that can change customer demand in mutually beneficial ways. For example, a planning analysis for a certain utility may show that offering interest-free loans for home insulation will be cost-effective by reducing the utility's demand peaks and its customers' energy bills. In response to a need evident since the groundswell of demand-side activity in the late 1970s, formal planning brings a systematic approach to the selection of the most cost-effective action or combination of actions for a given utility.

Although the emphasis on structured planning is a recent development, efforts to influence the demand for electricity are as old as the utility industry itself. Back in the 1890s in New York City, virtually the only load at Thomas A. Edison's Pearl Street generating facility was nighttime lighting. So he hired people to find and promote daytime uses for electricity. The electric motor, then a fledgling technology, was a perfect candidate, and utility loads grew around the clock as electric motors began taking over the heavy work in industry, businesses, and homes.

These two examples make an important point about demand-side activity: It is not just for reducing loads or just for building loads. It involves both—and all the load redistribution options in between.

For utilities with strong load growth, curtailing demand can defer the need for costly new construction. For those with ample reserve margins, building load can improve the return on investments already made. Even those utilities with a good overall match between capacity and demand can cut operating costs by redistributing demand more evenly throughout the hours of the day or the days of the year.

In this more comprehensive approach to utility planning, the planner must first identify broad utility goals. Say that one such goal is improved financial performance. The next step is defining tactical objectives, such as construction deferral or increased revenues, that will bring the utility closer to that goal. The process then narrows down to translating these tactical objectives into desired load shapes. Formal demand-side planning targets specific load shape objectives.

Although the possibilities for changing load shapes are infinite, five general types of change illustrate the range. The first three are classic load management techniques for improving utility load curves by smoothing out the peaks and valleys of customer demand. Peak clipping reduces system peak loads, valley filling builds off-peak loads, and load shifting moves demand from on-peak to off-peak periods.

Another possibility, strategic conservation, reduces total energy use without necessarily reducing peak demand. In choosing this objective, the utility planner takes into account the conservation actions that would occur naturally and then evaluates the cost-effectiveness of utility programs to stimulate or accelerate those actions. The fifth possibility for changing a utility's load profile is strategic load growth, which means an increase in beneficial sales.

In the last two cases the strategic aspect is selectivity. Such objectives are pursued only in carefully chosen end-use markets where load changes would benefit both utility and customer.

Once the utility has targeted its load shape objectives, what then? Under the demand-side umbrella the planner can find a diverse group of options for meeting those objectives: load management, strategic conservation, customer generation, innovative rates, industrial electrification, new uses for electricity in the residential and commercial sectors, and adjustments in market share. What they all have in common is the potential to alter utility load shapes. Choosing just the right option or combination of options to do this effectively is the next step in the planning process.

Trimming and shaping loads

Load management addresses the need to improve plant utilization by making customer demand more complementary over time to the available capacity. Perhaps the most familiar form is direct utility control of customer appliances to clip system peaks. A recent nationwide survey of utility end-use projects (EM-3529) shows more than a fivefold increase in utility load control projects between 1977 and 1983. Further, nearly 75% of these projects are now classified as broad-based implementations rather than tests, whereas the split was nearly even as recently as 1981.

The 218 utility load control projects reported in the survey involve more than 1.5 million separate loads. Most of them are residential, with electric water heaters (650,000) and central air conditioners (515,000) topping the list. Other applications include residential space heating systems (50,000), swimming pool pumps (260,000), and irrigation pumps (14,000). More than 85% are directly utility-controlled by installation of a remote communications link, such as a radio, ripple, or power line carrier. The remainder use "smart" controllers, which are set according to utility parameters or depend on customer self-control in response to some incentive offered by the utility.

Minnkota Power Cooperative, which supplies 12 rural electric cooperatives in Minnesota and North Dakota, has relied on demand-side planning to select those options that will be most cost-effective in softening its severe winter peak and boosting its annual load factor. One choice has been load control by means of dual-fuel space heating.

Minnkota's roughly 15,000 dual-fuel systems, which add electric resistance heaters to oil-burning space heaters, are designed to operate on electricity 90% of the time and on oil 10% of the time. When demand on the utility begins to peak, Minnkota operators switch these directly controlled customer heating systems from electricity to oil. Average demand reduction is about 8 kW per load. Altogether these systems account for the majority of the utility's 220-MW load-shedding capability. Customers suffer no discomfort from the switch, and the utility is able to maintain a competitive stance and build off-peak load while clipping its winter demand peak.

The results of this and other carefully planned demand-side activities at Minnkota show a dramatic improvement in annual load factor—from a low of 48% in 1976 to 63% by 1983. Sales and revenues are up, while rates remain at least 36% lower than they would have been without these efforts. The average Minnkota customer saves about $400 a year on energy bills.

Conservation is another demand-side option for the utility planner. Although most utilities in the United States have instituted some sort of conservation services for their customers, those finding themselves short of critical fuels or generating capacity have pursued this option more vigorously. Northwestern utilities that rely on hydropower turned to conservation when water resources became strained, and the oil pinch forced many northeastern utilities to make similar demand-side moves. Financing or regulatory constraints that cramp capacity growth often have the same effect.

Thirteen utilities participated in a recently completed conservation study (EA-3585). Their 187 conservation programs provide information, direct technical assistance, financial incentives, special rates, and demonstrations to customers. For example, Pacific Gas and Electric Co. uses bill inserts promoting a variety of energy-saving devices for the home. Florida Power & Light Co. provides direct technical assistance in the form of pool pump audits and adjustments for owners of the estimated 216,000 swimming pools in its service area. Northeast Utilities, like many others in this group, offers low-interest loans to customers for weatherization. Duke Power Co. offers a special conservation rate, 12–14% below the average space-heating rate, to residential customers who meet insulation requirements. And the Tennessee Valley Authority has been very active in demonstrating energy-saving solar technologies in its service area.

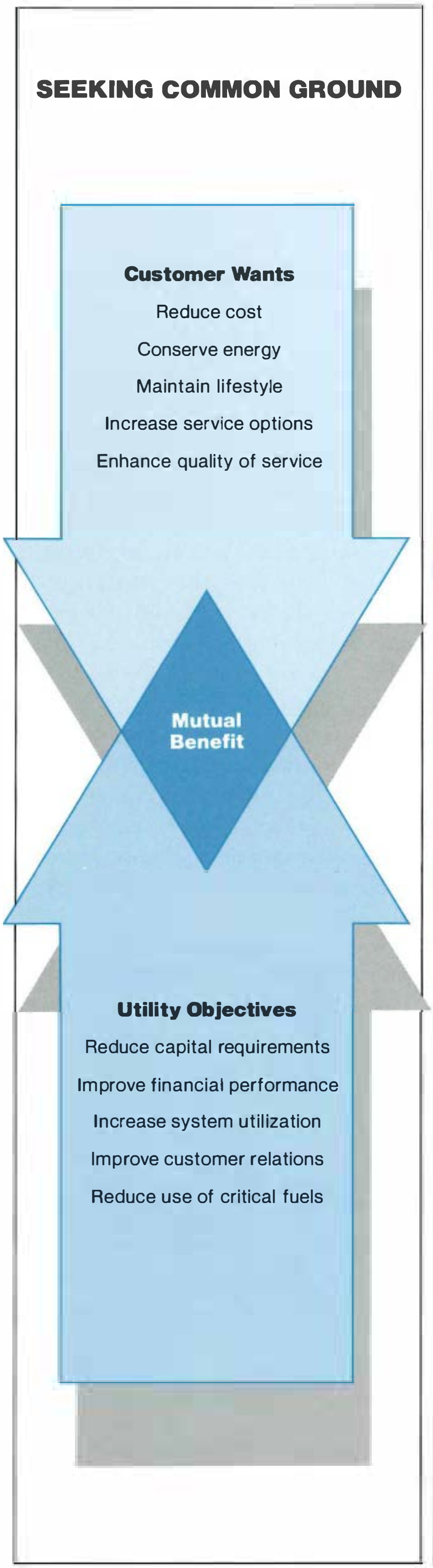
Promoting customer generation of electricity is another demand-side option planners can choose to relieve the strain on utilities that are hard pressed to keep up with demand growth. The idea is to shift some of the burden of investment in power generation equipment from the utility to the user. Possible candidates range from rural customers who generate small amounts of power from their own windmills to large manufacturing concerns that cogenerate electricity with process steam from a common fuel source. Some are self-sufficient, but most maintain a relationship with the local utility, buying backup power when they need it and/or selling their surplus power to the utility grid.

Nowhere in demand-side planning is the influence of utility rate structures more evident than in the case of customer generation. If utilities pay high prices for customer power and charge low rates for backup, they encourage customer generation. Low purchase rates and high backup rates have the opposite effect. Under the Public Utility Regulatory Policies Act (PURPA) of 1978, the federal government has mandated state procedures that result in purchase rates encouraging customer generation.

Innovative rates stimulate various types of customer behavior, and they play an important role in many other areas of demand-side planning as well. One of the most familiar examples is the time-of-use (TOU) rate.

The first utility TOU meter was patented back in the late 1800s, but only in the past decade have electric utilities begun experimenting with TOU rates on a large scale. Utilities can use the TOU rate to shift loads by rewarding customers for using electricity during off-peak rather than on-peak hours. According to a recent survey, 106 utilities now offer TOU rates (EA-3830). General Public Utilities Corp., with more than 31,000 customers on TOU rates, is one of the leaders in this field.

Interruptible service rates are yet another innovation, one that 86 utilities nationwide are trying. The industrial customer agrees to an interruption of service, usually with advance notice, at times when the utility finds it necessary



to clip system peaks. Commonwealth Edison Co. of Chicago has offered both interruptible service rates and favorable rates to industrial cogenerators in support of its demand-side planning objectives—in this case, controlling demand peaks and deferring the need for any new capacity beyond that already under construction.

The foregoing options that reduce or control loads are important for planners working to improve financial performance and hold down costs to customers. Increasingly, however, planners are blending their load-restraining programs with selective efforts to build loads. Sometimes the effort focuses on filling valleys in the utility load curve. Other times the emphasis is on strategic load growth (increasing the utility's total sales).

The objective is to use existing generating capacity and achieve a reasonable return on the investment that it represents. As EPRI's Gellings explains, "With capacity margins what they are, some utilities are not earning enough revenue to amortize all that capital. The money that they have invested in generating capacity is not yielding enough revenue to provide adequate cash flow."

One solution to this bind is to raise rates. But this is neither popular with customers nor always effective. Another solution is to take an active role in influencing demand.

Building loads

Three remaining options under the demand-side umbrella are of special interest to those planners whose load shape objectives include valley filling and/or load growth: industrial electrification, new uses for electricity in the residential and commercial sectors, and adjustments in market share.

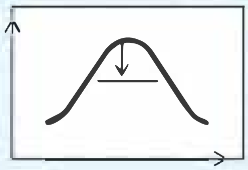
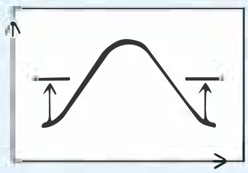
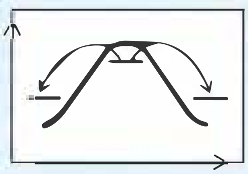
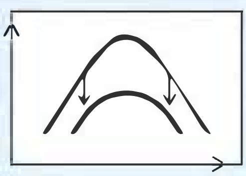
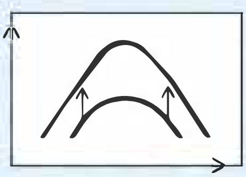
The trend is toward increasing use of electrically based processes in the industrial sector because of the great boosts in productivity that electrotechnologies can provide. For example, electric arc furnaces, which can generate the intense heat necessary to recycle steel scrap efficiently, now offer a shortcut to profitability in the innovative minimill segment of the steel industry. Similar trends are occurring in the automotive, textile, paper, food, and other major industries.

Baltimore Gas and Electric Co. is one utility that plans to benefit from industrial electrification. To build industrial loads, BG&E is encouraging the use of electrotechnologies for process heating. It exceeded its goal of 10,000 kW of new load from this source in 1983. In addition, BG&E is targeting new electricity loads for comfort heating and outdoor lighting in the industrial sector, which together yielded an increase of about 95,000 kW in 1983. To some extent, this success was aided by a rise in the rates for natural gas. The BG&E program emphasizes the importance of trade allies—contractors, architects, and engineers—as well as the general economic development of its service area.

Closely related to electrification in the industrial sector are new uses of electricity for the residential or commercial customer. The small computer, for example, represents a growing load that barely existed 10 years ago. The closest analogy may be the television set, which in 1950 was an exciting new item expected to consume a substantial 20 billion kWh by 1980 if, as expected, every home had one. What happened is that television sets in 1980 consumed 35 billion kWh—75% more electricity than the amount predicted.

Consumers had more television sets per home and watched more hours per day than forecasters had expected. Consumer enthusiasm for color TV, which uses about three times as much electricity as a black-and-white set, further boosted utility sales, even though advances in technology had cut the consumption of a black-and-white set to one-ninth its 1950 level. If the home computer takes off as the television set did—and recent research shows that

LOAD SHAPE AND DEMAND-SIDE ALTERNATIVES

Utility Load Shape Objectives		Examples of Customer Options		
		Residential	**Commercial**	**Industrial**
Peaking clipping, or reduction of load during peak periods, is generally achieved by directly controlling customers' appliances. This direct control can be used to reduce capacity requirements, operating costs, and dependence on critical fuels.		• Accept direct control of air conditioners	• Accept direct control of water heaters	• Subscribe to interruptible rates
Valley filling, or building load during off-peak periods, is particularly desirable when the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances can decrease the average price.		• Use off-peak water heating	• Store hot water to augment space heating	• Add nighttime operations
Load shifting, which accomplishes many of the goals of both peak clipping and valley filling, involves shifting load from on-peak to off-peak periods, allowing the most efficient use of capacity.		• Subscribe to time-of-use rates	• Install cool-storage equipment	• Shift operations from daytime to nighttime
Strategic conservation involves a reduction in sales, often including a change in the pattern of use. The utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of utility programs intended to accelerate or stimulate conservation actions.		• Supplement home insulation	• Reduce lighting use	• Install more-efficient processes
Strategic load growth, a targeted increase in sales, may involve increased market share of loads that are or can be served by competing fuels, as well as development of new markets. In the future, load growth will include greater electrification—electric vehicles, automation, and industrial process heating.		• Switch from gas to electric water heating	• Install heat pumps	• Convert from gas to electric process heating

nearly 12% of the population already own or have access to a computer—the impact on utility loads could be quite significant in coming decades.

What's more, the garden, the playing field, and the shopping center are coming indoors in the form of the greenhouse, the domed stadium, and the enclosed mall. The energy required to heat, cool, and ventilate these enclosures will also represent very substantial new loads. Although the idea of automated homes and office buildings, with multiple functions controlled electronically by a computerized brain, may sound like starship science fiction, the reality is not so far away. Such innovations will mean a greater reliance than ever before on systems powered exclusively by electricity.

One role the utility can play is to encourage the development of these new applications through advertising or promotion, through joint ventures with retailers or contractors, and through pricing options that support such uses. On the other hand, the utility can take a neutral stance, merely serving whatever plan develops, or it can discourage new uses by its electricity pricing or service policies. Choosing the first posture, active encouragement, is most effective for building loads.

Adjustments in market share, a final option in demand-side planning, also focus on increasing utility loads. The difference is that these loads already exist and usually are served by gas or oil. For example, the aim here may be to win some of the home-heating load now served by fossil fuels.

Philadelphia Electric Co. is actively promoting electric heat pumps for this purpose. It captured 64% of the new home market for electric heating in 1983, with heat pumps accounting for about half the total. The goal for 1984 is 70%, with planned shares of 20% for resistance heating and 50% for heat pumps.

Facing a low load factor (47%) caused by a high summer air-conditioning peak and with sufficient capacity to allow for load growth, planners at Iowa Power and Light Co. have also selected the heat pump to boost winter sales. Further, like an increasing number of utilities, IP&L uses structured planning to identify an optimal combination of demand-side moves: conservation in some areas, load management in others, and load building in still others. Demand-side planning in its many forms is proving to be a very flexible tool for achieving utility load shape changes, whatever those desired changes may be.

Current research

EPRI's demand-side research is appropriately diverse. Three of the Institute's six technical divisions—the Energy Analysis and Environment (EA&E), Energy Management and Utilization (EMU), and Electrical Systems (ES) divisions—are actively engaged in some type of exploration to support the demand-side approach. EPRI's recently published *End-Use Catalog: R&D Projects and Products* examines over 200 end-use activities being managed by these divisions.

Planning activities center in the EA&E Division. Its Demand and Conservation Program has more than 50 projects in forecasting and planning electricity demand for all sectors of the economy. Demand-side management (RP2548) is a $1.6 million project that will generate some 13 guidebooks, providing utilities with the tools and information they need to undertake their own demand-side planning programs.

Other EA&E projects are exploring the effects of rate innovation and are creating techniques to gauge consumer response. Other projects are developing models that integrate supply and demand factors for utility planning and investment decision making. One such model, the load management strategy testing model (LMSTM), is already in widespread use. In addition, EA&E is evaluating the risks associated with demand-side options and incorporating the results into planning tools.

The EMU Division provides the technologic cutting edge for implementing many of these demand-side plans. It develops and tests new methods of load management, provides conservation technology, and investigates how industrial loads can be reshaped through process electrification or customer generation. Further, EMU is sponsoring vigorous development of advanced heat pumps that will provide electric heating/cooling for a wide variety of residential and commercial applications.

The ES Division also plays a vital role in implementing certain types of demand-side options. It provides the technologic capability to control customer appliance use through direct communications links. In addition, its research develops the complex metering capability necessary to support TOU pricing and other innovative rates designed to influence patterns of customer demand.

Edison Electric Institute is making a major contribution to the industry's demand-side effort. As part of a national marketing program, EEI is preparing a 12-volume *Power of Choice Bookshelf* to help utility customer service and marketing managers develop innovative electricity demand management programs. The American Public Power Association and the National Rural Electric Cooperative Association are conducting ongoing demand management communication and demonstration programs with their members.

Load shape impacts

Demand-side planning offers a fresh way of looking at the utility universe and a varied menu of options. But what real difference will it make?

The most tangible point of impact is the planning target: load shape. Gellings estimates a possible 10–12% reduction in utility peak loads. Successful peak clipping on this scale could translate to some $100 billion in capital savings from capacity deferral over the next 10–20 years.

Such savings are unlikely to accrue in the near future, however, because the impetus for some of the incentives has slackened. With demand growth already down from the historic 7% level to an annual average of about 2–3%, many utilities have now resolved the energy and capacity shortages that triggered load-trimming activity in the late 1970s. Conservation and reduction in load growth are no longer quite as pressing as before.

"Right now," comments Gellings, "strategic load growth has become very important. That includes both industrial electrification and new uses or increased market share in the residential and commercial sectors. These options are now of greater interest to 30% or more of the nation's utilities." However, the outlook for strategic load growth is mixed, in Gellings's view. Industrial electrification will forge ahead, he believes, owing to the remarkable efficiency of the emerging electrotechnologies. But the very efficiency that makes these technologies attractive will reduce their load-building effects. Nationwide, the prospects depend heavily on the extent to which electric energy penetrates industrial markets traditionally served by gas or oil.

The residential and commercial sectors offer the greatest opportunities for utility load building. "There is solid potential in baseload uses like home computers," Gellings observes. "And I think there's room for real growth in the commercial sector with ideas like the automated office building. We've only scratched the surface there." Between now and the year 2000, utility loads in the commercial sector are expected to grow nearly 40% to about 730 GWh annually.

Weather-related end uses in the residential and commercial sectors will grow less rapidly for the same reason that will restrain load growth in industry: gains in efficiency. Still, the widespread introduction of electric heat pumps could boost combined heating and cooling loads by some 25%, representing roughly a $6 billion increment to utility revenues. The main obstacle to achieving this potential is strong competition from the gas industry, which is also working on advanced high-efficiency technologies.

So the load shape impacts of demand-side planning could be substantial. These load shape changes translate into dollars saved and dollars earned, and they have a direct and tangible effect on utility financial performance.

But what about the less tangible impacts? They too can exert a powerful influence on a utility's well-being over the long term. That is why the demand-side approach emphasizes not only financial performance but also customer relations.

Customer focus

Central to the concept of demand-side planning is mutual utility and customer benefit.

"For years," says Gellings, "we have responded to customer demand without questioning it. Customers, for their part, have consumed electricity and paid their bills at the end of the month without knowing exactly how their money was spent. Can you imagine going into a supermarket with no weights and no measures and no prices marked on the goods, selecting your market basket, going to the cash register, and only then knowing what you've spent and what you've gotten for it?"

Gellings stresses the need for better two-way communication in developing a new partnership between the utility and the customer. "We will form a buy-sell arrangement," he says, "a mutual needs agreement.

"I hope this is the beginning of a whole new philosophy that will include changing the way we meter and display information to customers. We have to give them more information—a better breakdown by end use—so they'll have a greater sense of control over their electric bills."

The sense of control that comes from having choices is critical in developing a solid accord with customers. That is why Gellings feels TOU rates and other options that leave consumption choices in the customer's hands will probably prove to be among the most effective means of meeting demand-side goals.

Because demand-side planning spotlights customer wants and needs in all their diversity, utilities are finding that they need a more detailed understanding of the factors that influence customer decisions. One of the analytic tools developed by EPRI for this purpose is the residential end-use energy planning system (REEPS).

REEPS breaks its analysis down so that utilities can study individual market segments. Within the market for central air conditioning, for example, REEPS has shown that purchase decisions are affected mostly by customer income, whereas utilization decisions depend mostly on electricity price. Total use, which represents the combined impact of these two types of decisions, is influenced more by income than by price. The upshot is that utilities wanting to modify air conditioner use as part of their demand-side strategy would do well to use income incentives (e.g., cash rebates) rather than price incentives (e.g., special rates).

Different relationships may hold for different end-use markets. REEPS and other planning programs now under development can help utilities design demand-side programs with an effective balance of income and price levers. The idea is to provide the type of incentives that research has shown customers to prefer.

More-detailed information on customer preferences and related costs/benefits to the utility is perhaps the most pressing need in the development of demand-side planning. During the rush to implement early demand-side

STEPS TO DEMAND-SIDE PLANNING

Define utility's broad objectives

Determine load-shape objectives

Select end uses

Identify alternatives

Evaluate and select activities

Develop market implementation methods

Customer Adoption Technique	Objective	Specific Alternative
Customer Education	Increase customer awareness of utility programs	Bill inserts, brochures, information packets, displays, direct mailings
Direct Customer Contact	Encourage customer response to utility programs	On-site energy audits, workshops, energy clinics
Advertising and Promotion	Increase customer awareness of new programs and influence customer response	Radio, television, newspapers, magazines
Alternative Pricing	Provide customers with pricing signals to encourage a desired market response	Demand rates, time-of-use rates, off-peak rates, seasonal rates, inverted rates, interruptible rates, promotional rates, conservation rates
Direct Incentives	Reduce up-front purchase price of hardware to increase market penetration	Low- or no-interest loans, cash grants, rebates, subsidized installation or modification of equipment

Formal demand-side planning includes eight steps (EA/EM-3597).

- Establish program objectives
- Identify possible changes in load shape and the demand-side options for accomplishing those changes
- Determine methods of selecting the most beneficial changes and options
- Forecast load shape impacts
- Develop a marketing plan
- Develop an implementation plan
- Develop an impact-monitoring plan
- Take action

The Southern Company, with a large interstate service territory, is working on a systematic demand-side methodology called the total energy resource planning system (TERPS).

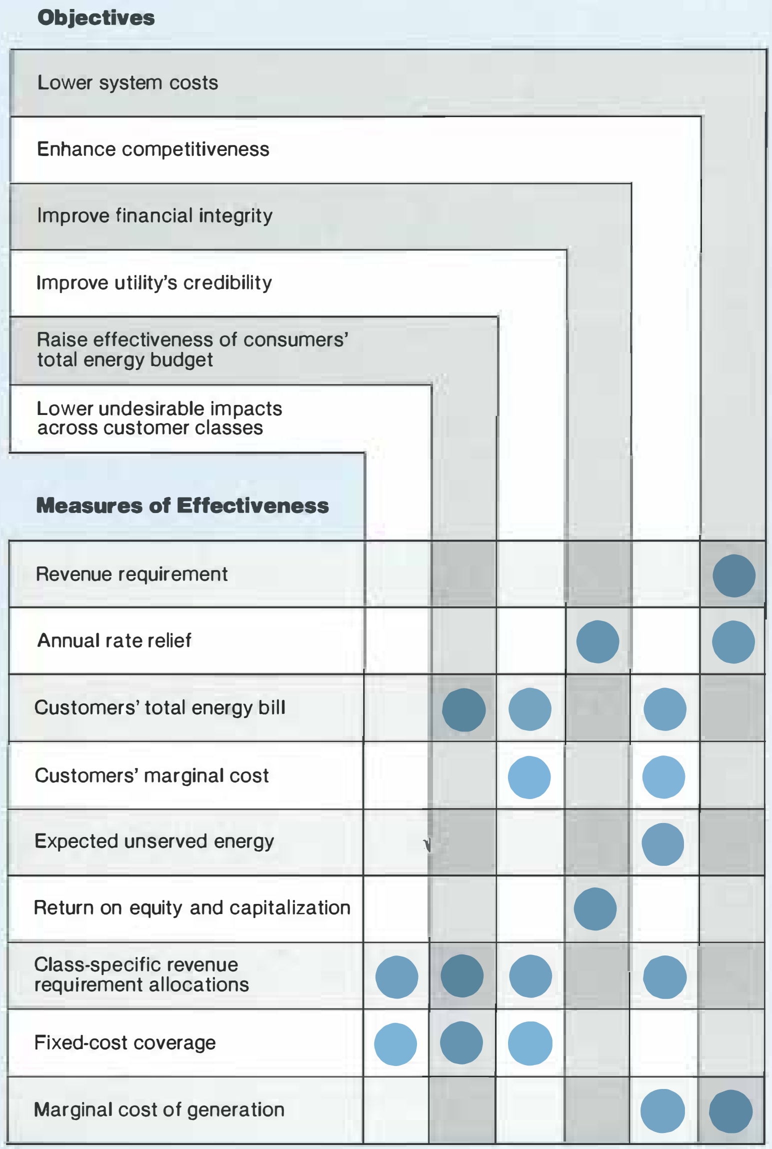
Its approach is unique in that it identifies objectives and a process for selecting load shape changes prior to considering specific options for accomplishing these ends. Planners identify an objective (e.g., lower system costs), develop corresponding load shape objectives, and then evaluate them through the use of production costing and financial models. In this way, the utility knows how much it would have to spend to achieve certain load shape changes.

To date TERPS has focused on the first four steps of the planning process. Step 1 establishes the companywide financial and customer relations objectives shown in the matrix. Step 2 identifies the load shape changes being considered to meet these objectives—load shifting within the summer season and valley filling during the winter season and annually.

Step 3 provides a method for evaluating the ability of each proposed change in load shape to satisfy the company's objectives. The effects of each load change type are compared with a base case system forecast. The comparison assesses the relative costs and benefits accruing to customers and to Southern Company shareholders under each set of load shape conditions.

Sensitivity analyses address a range of conditions by varying these dimensions: magnitude of load change, timeframe of study, customer class

THE PLANNING PROCESS



responsible for load change, and implementation cost of load change.

The load magnitude analysis shows the effects on the utility's generation expansion plan and production costs. The timeframe analysis indicates which strategies offer benefits in the short term, midterm, and long term. The customer class analysis shows how the revenue responsibility would differ for a given load change. The implementation cost analysis not only demonstrates the effects of high and lost cost but also addresses alternative rate-making treatments to cover the cost. So the sensitivity analyses in step 3 yield not only bandwidth estimates for the evaluation parameters but also information useful for designing load change strategies.

Step 4 focuses on measuring the benefits of specific load shape modifications. In the TERPS approach, altering the magnitude of load change affects the results of all the other sensitivity analyses. To minimize these confounding effects, one load change magnitude for each of the load shape objectives has been specified as the nominal change or base case. Downstream sensitivity analyses all use this base case, except when load change magnitude is varied to refine evaluation of strategy design.

So far, The Southern Company's demand-side planning shows a window of opportunity to add load by valley filling over the short term. The second type of load shape objective being considered, load shifting, looks attractive over the long term. With this information in hand—and after the selection of specific options to accomplish these load shape objectives—the utility will be in a position to consider the additional steps that deal with marketing, implement, and monitoring of the demand-side plan. □

programs, utilities often conducted this evaluation after the fact. Now, with a more thorough and systematic approach, projecting probable customer response to various options becomes an integral part of the planning process.

Taking the initiative

Demand-side planning is not a panacea. It is highly utility-specific. Current generating mix, customer load mix, end-use saturation levels, and demographics, as well as expected load growth, capacity expansion plans, load factor, load shapes for average and extreme days, regulatory climate, and reserve margins, all influence whether and how the demand-side approach can work for a specific utility. Still, demand-side planning offers a special opportunity for many utilities to take a hand in shaping the future.

The death-spiral hypothesis advanced by some critics of the industry suggests that utilities are caught in a spiral of rising production costs and sluggish demand. Rising costs increase prices, which further depress demand, and so on. This view reflects the dual assumption that utilities are captive to uncontrollable costs on the one hand and to mature markets on the other. But neither of these assumptions has to be the case.

Demand-side planning offers ways to cut both capital and O&M costs. Further, it offers a number of avenues to develop new markets for electricity without encouraging excessive or wasteful energy use. These new applications—computers, industrial lasers, advanced heat pumps for the home, to name only a few—benefit the customer and the utility. They are highly energy-efficient, so they help control customer energy bills at the same time as they build utility loads.

How, then, will the demand-side approach affect the way that utilities do business? "We will be a more efficient industry," predicts Gellings. "We will be a more competitive industry. And we will be closer to our customers." The change will be fundamental: "Customers will see a completely different industry—one that is more responsive, has a better understanding of their wants and needs, and offers a lower service cost than would be possible without demand-side planning.

"The potential for influencing demand has been tried and proved in this industry for years," says Gellings, "but we've never done it before in an organized manner. We've never before had a formal planning structure that would allow us to look at demand-side options in concert with supply-side options. Until we do that, we're not giving ourselves a fair shake at the full range of opportunities available." ■

Further reading

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This article was written by Mary Wayne, science writer. Technical background information was provided by Clark Gellings, Energy Analysis and Environment Division.

COOL WATER
Milestone for Clean Coal Technology

The nation's first commercial-size gasification–combined-cycle power plant is now on-line, producing electricity from coal by a clean, efficient, and economically competitive process.

In late May and early June of this year the Cool Water coal gasification–combined-cycle power plant was brought on-line as a new type of clean, coal-based power-generating facility, producing about 100 MW (net) of electricity for customers of Southern California Edison Co. (SCE). The plant's novel appearance reflects a revolutionary design, for it represents the first commercial-scale demonstration of the integrated gasification–combined-cycle (IGCC) technology, a new concept for using coal in an environmentally acceptable way. Built entirely with private funds, the new facility was finished under budget and ahead of schedule, with field construction taking only 28 months.

Acting on behalf of the utility industry, EPRI made the largest financial contribution to the program, an estimated $69 million of an estimated final cost of $263 million. The fact that this represents by far the greatest funding commitment the Institute has ever made to a single project illustrates the potential this technology may have for utilities. In addition to performing better than today's toughest environmental standards, IGCC holds the promise of providing electricity at rates competitive with conventional coal technology but in relatively small modules that can be built much more quickly than present baseload units.

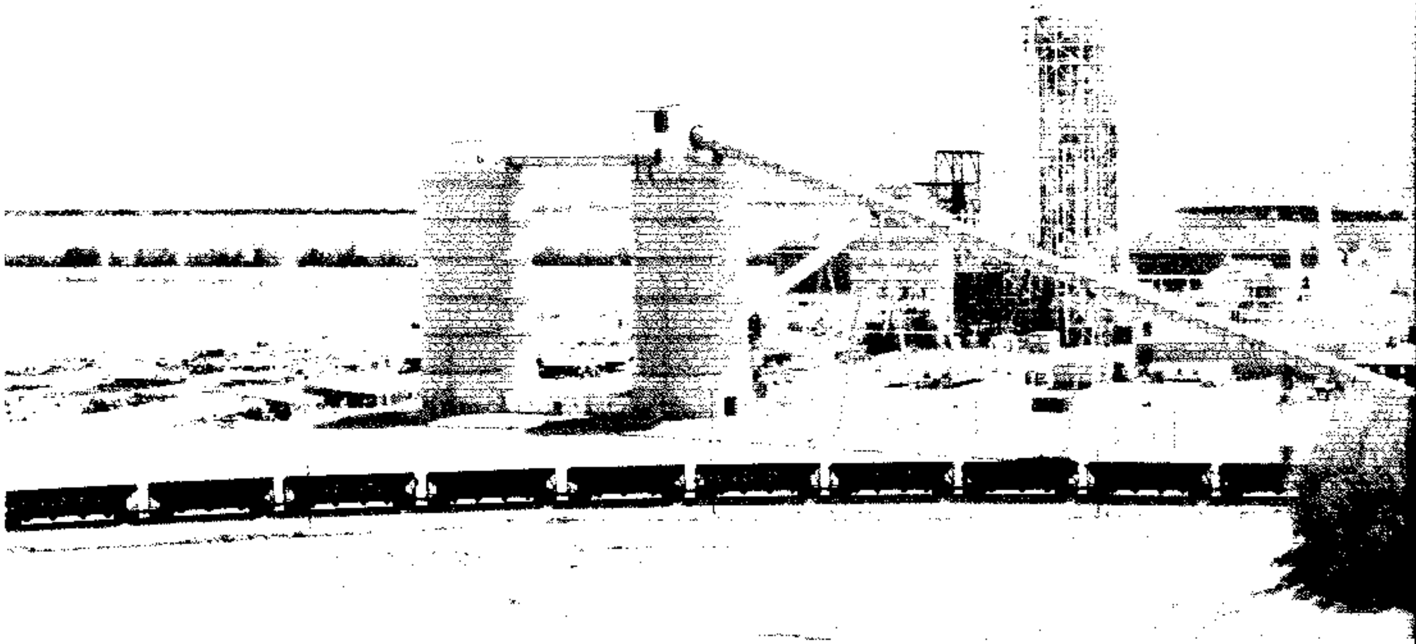
Although Cool Water has experienced several of the minor startup problems common in new plants, its overall performance during the first few months of operation has been, in the words of Dwain Spencer, vice president for the Advanced Power Systems Division, "simply incredible. In fact, during the month of September the plant achieved an on-line capacity factor of over 70%." A five-year program is now under way to confirm the attractive features of the IGCC concept by demonstration at commercial scale. The program's test and demonstration staff, headed by John McDaniel of EPRI, will conduct studies of plant performance at steady state, tests of dynamic response during load following, materials evaluation, and environmental analysis.

Cooperative effort

The Cool Water project had its origins in conceptual studies conducted during the mid 1970s to find new ways of reducing utility dependence on imported oil by improving the environmental acceptability of coal-based power generation. These studies indicated that IGCC technology offered unique advantages. By first converting coal to a clean-burning gas, it could meet the strictest air pollution standards without the need for add-on stack gas scrubbers. And by recovering the heat produced during gasification to help generate electricity in a combined cycle of gas and steam turbines, it could attain efficiencies greater than those achievable with conventional coal-fired plants equipped with stack gas scrubbers.

In 1978 SCE and EPRI conducted a joint study to define the appropriate scale and design approach of an IGCC demonstration plant using the Texaco coal gasification process and based in part on an earlier SCE-Texaco study for a gasification plant. The following year SCE and Texaco, Inc., signed an agreement that established specific objectives and obligations for such a project: SCE would provide the site, necessary services, and plant operators; Texaco would share its proprietary gasification process and provide startup assistance and operations support.

Then the search began for additional partners that could provide both the needed technical expertise and an equity stake of at least $25 million apiece. These partners now include EPRI, which provided key engineering design bases and technical and financial review of progress and will evaluate the plant's test data for the utility industry; Bechtel Power Corp., the principal engineer-constructor; General Electric Co., which



is providing the combined-cycle generating equipment; and the Japan Cool Water Program Partnership, a group of Japanese companies that are providing technical assistance and support. In addition, the Empire State Electric Energy Research Corp. (Eseerco), a group of New York State utilities, and Sohio Alternate Energy Development Co. have contributed $5 million each in return for access to privileged data produced by the testing program.

Cool Water had a close call in 1981 when fund raising slowed and the start of construction was postponed for several months. In December EPRI's Board of Directors increased the Institute's commitment in the project from $50 million to $65 million, with an obligation to add up to $61 million more if needed. This increase, together with additional commitments from other participants, allowed construction to begin.

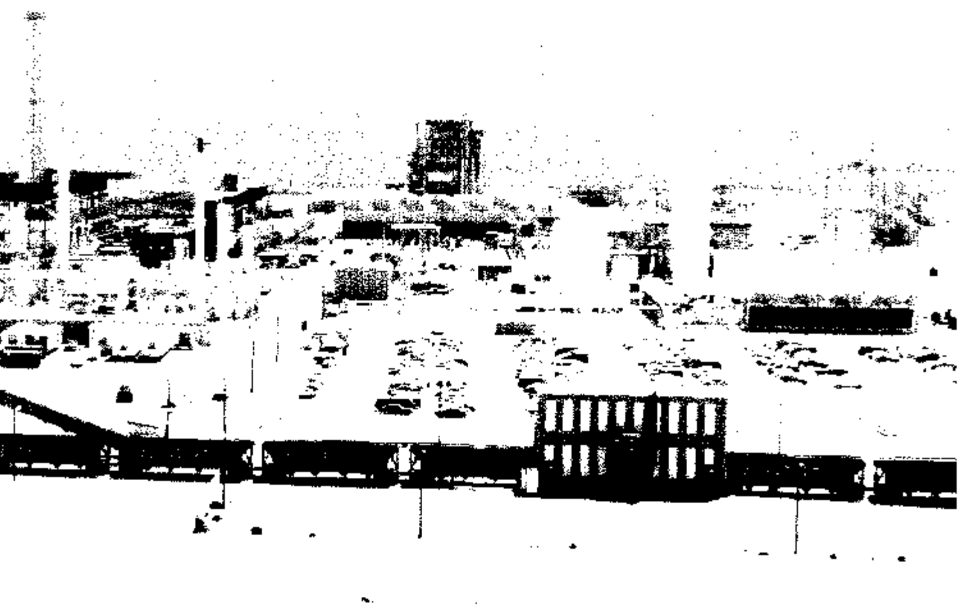
"EPRI's potential commitment of more than $100 million to Cool Water was a clear message that our Board of Directors believed this new, clean coal technology should be demonstrated at a commercial scale," says Spencer. "I believe the Board's foresight has been proved by the events of the past few months as Cool Water has come on-line successfully and as interest in coal gasification has grown within the utility industry, as well as in other industries."

Two important changes in the business climate have occurred, however, since the time when Cool Water was first being considered. On the one hand, load growth projections have been reduced so that new plant additions could come later than previously predicted. On the other hand, concern over acid rain has led to new efforts to tighten pollution standards and has prompted utilities to increase their efforts to seek better ways of using coal. By the time new plants are needed, the competitiveness of IGCC, compared with other coal technologies, should have been confirmed.

At the same time a decline in the cost of oil-based generation (perceived by many to be only temporary) has had a negative effect on anticipated revenues from Cool Water as a result of regulatory limits imposed on SCE's rates for sales of electricity from the project. This added risk has been largely offset, however, by price support guarantees from the U.S. Synthetic Fuels Corp. (SFC). For the first five years of operation, SFC is committed to helping cover the cost of producing syngas at the plant if revenues from the sale of electricity are not sufficient to pay for operating and maintenance expenses. The Cool Water project was the first recipient of such SFC backing, which could reach a maximum of $120 million, depending on the future avoided cost of electricity.

A marriage of technologies

"All participants had both their reputations and a financial risk at stake in the Cool Water project," comments Thomas O'Shea, EPRI project manager for Cool Water. "This was a key factor in achieving tight cost and schedule control, which, in turn, resulted in the plant coming on-line ahead of time and under budget. There was good project management and proper oversight by the Board of Control and the Management Committee." The project was also exceptionally well planned, with design details being about 50% complete before the site was cleared—well above the average for utility projects. In addition, all participants made serious commitments of manpower to the project, union relations at the site were good, a slack market for some suppliers helped keep deliveries on time, and the general rate of inflation



Coal silos and the tower containing a gasifier and heat exchangers dominate Southern California Edison Co.'s Cool Water site near Barstow in the southern California desert. Here 1000 tons of coal daily feed an integrated gasification and combined-cycle power plant rated at 120 MW (less 20 MW for plant auxiliaries). The power section of the demonstration plant is at the center (slender dark stack). Other generating facilities, a 470-MW gas-fired combined-cycle plant (two white stacks at center), and two gas-fired steam units totaling 145 MW (dark structure in right background) share the site, as does an air separation plant (white tanks and column at far right) that supplies oxygen to the IGCC plant.

was lower than anticipated.

This record, plus the successful startup, should help encourage the stream of utility executives that are expected to visit the site over the next five years. "I think they'll be pleasantly surprised," O'Shea asserts. "Each time I enter the plant gate I make a bet with myself as to whether the system is running or not. Whenever I think it isn't, I'm invariably wrong, because the operation is so quiet and the stack is so clean.

"Although the plant has only just embarked on its operational phase," O'Shea continues, "we have already confirmed several of our early projections, including the estimated capital cost, short construction and commissioning time, design coal throughput, and plant power output. In addition, we have confirmed the coal slurry concentration, carbon conversion, and the initial heat rate and capacity factor."

Trying to join two very different technologies into one plant, while drawing on expertise from two widely separated industries, does pose some unique challenges. Chemical process vessels operating at high temperature and pressure must be mated with power generation systems designed to burn gas and create steam with the least amount of wasted energy. "Designers from two industries were forced to work together," explains Ronald Wolk, director of the Advanced Fossil Power Systems Department. "In addition, safety regulations and operating procedures related to both technologies had to be adapted to meet the rigorous demands of a sophisticated, first-of-its-kind plant."

Gasification itself takes place in a relatively small vessel near the top of Cool Water's main structure. Oxygen and a coal-water slurry enter from above and react quickly as they flow down through the gasifier. This partial oxidation reaction produces a medium-Btu gas consisting mainly of carbon monoxide and hydrogen. Sulfur in the coal is converted to hydrogen sulfide gas, with a small amount of carbonyl sulfide and other sulfur compounds. The mixture of hot gases and molten slag emerging from the bottom of the gasifier goes immediately into a radiant cooler, where the slag solidifies while falling vertically and the radiant heat recovered is used to generate high-pressure steam in a surrounding water wall. After the slag is separated, the syngas enters a convection cooler where it passes over tubes filled with water to recover additional heat.

The two syngas coolers used at Cool Water are the largest shop-fabricated pressurized heat exchangers ever built. Each is 15 ft (4.6 m) in diameter and 120 ft (36.6 m) in length and weighs over 600 tons. The coolers were shipped to the site on a special rail car with hydraulic supports that can shift a load sideways when going around tight corners. Being able to build and deliver such units in a single piece has several advantages, including lower cost and greater quality control, and such techniques are being examined as an important key to building economical modular gasification–combined-cycle power plants of 250–300 MW capacity.

To remove sulfur the gas passes through a Selexol unit (a proprietary process of Norton Co.), where a solvent absorbs the gaseous sulfur compounds. A SCOT (Shell-Claus offgas treatment) system then concentrates the hydrogen sulfide and feeds it to a Claus catalytic unit for conversion to elemental sulfur. This by-product is now being sold for use in making fertilizer.

Prior to reaching the combustion turbine, the gas passes through a saturator vessel where its temperature is raised to

Dedication of the Cool Water plant took place on October 17 with the unveiling of a plaque and speeches by representatives from each of the participants. The keynote address was delivered by U.S. Senator Malcolm Wallop of Wyoming. A recurring theme among the speakers was the potential importance of IGCC technology for preserving the viability of coal as an option for future power generation.

"This technology is the most effective way to eliminate deleterious emissions from utility generating plants," said EPRI President Floyd L. Culler, "which makes it the best new option for meeting environmental requirements while producing power at competitive prices." He emphasized the importance of considering IGCC when "decisions about air quality and acid rain legislation are made. The atmospheric burden of acid gases can be reduced with this superior technology more effectively and at less cost than with scrubbers."

Wallop called the occasion "a historic date in America's quest for energy independence." Drawing on his experience as a member of the Senate Committee on Energy and Natural Resources, he said he is still profoundly worried about the security of America's energy future and noted that U.S. oil imports increased 30% between the first half of 1983 and the first half of 1984. Citing the need to prepare for future energy shocks even in the midst of apparent abundance, Wallop congratulated the Cool Water partners on their foresight in building a plant that makes better use of ample domestic coal supplies.

The most highly personal tribute to the new plant expressed during the ceremonies was that of William R. Gould, chairman and chief executive officer of Southern California Edison. Noting that he was to retire in a few months, Gould said, "I can't help but reflect that this is a nice way to go—kind of on a crescendo." The company's decision to become the host utility for Cool Water was part of a continuing program to find better ways of using new and alternative

An hour-long ceremony with an invited audience of 550, the national anthem by the high school band from Barstow, a press conference, and a day of plant tours marked the October 17, 1984, dedication of the Cool Water facility.

The new Cool Water plant, its dedication, and a commemorative plaque were acknowledged by the keynote speaker, Senator Malcolm Wallop of Wyoming (left), and representatives of the organizations that made it possible: Louis Tomasetti of General Electric Co., Kazuo Fujimori of the Japan Cool Water Program Partnership, Harry Reinsch of Bechtel Power Corp., William Gould of Southern California Edison Co., Willis Reals of Texaco Inc., and Floyd Culler of EPRI.

energy resources. "Although the energy crisis is now dormant but still threatening," he said, "we couldn't afford to remain stagnant."

Willis B. Reals, senior vice president of Texaco, noted that the gasification technology used at Cool Water is not in itself really new because Texaco has been working on the process since 1948. He emphasized, however, that "we've come a long way" since then and added that the cooperative effort evident at Cool Water "answers a critical need for the future of the country—a cleaner, more secure energy future for all of us."

The importance of Cool Water's rapid construction was noted by Louis V. Tomasetti, executive vice president of General Electric. "We are proving that new coal-burning power generation capacity can be installed in almost real time." Because of this, decisions on new plants can be made "without taking shareholders and customers on a 10- or 12- or 14-year journey into a murky future on a project that burns interest money at a faster rate than fuel."

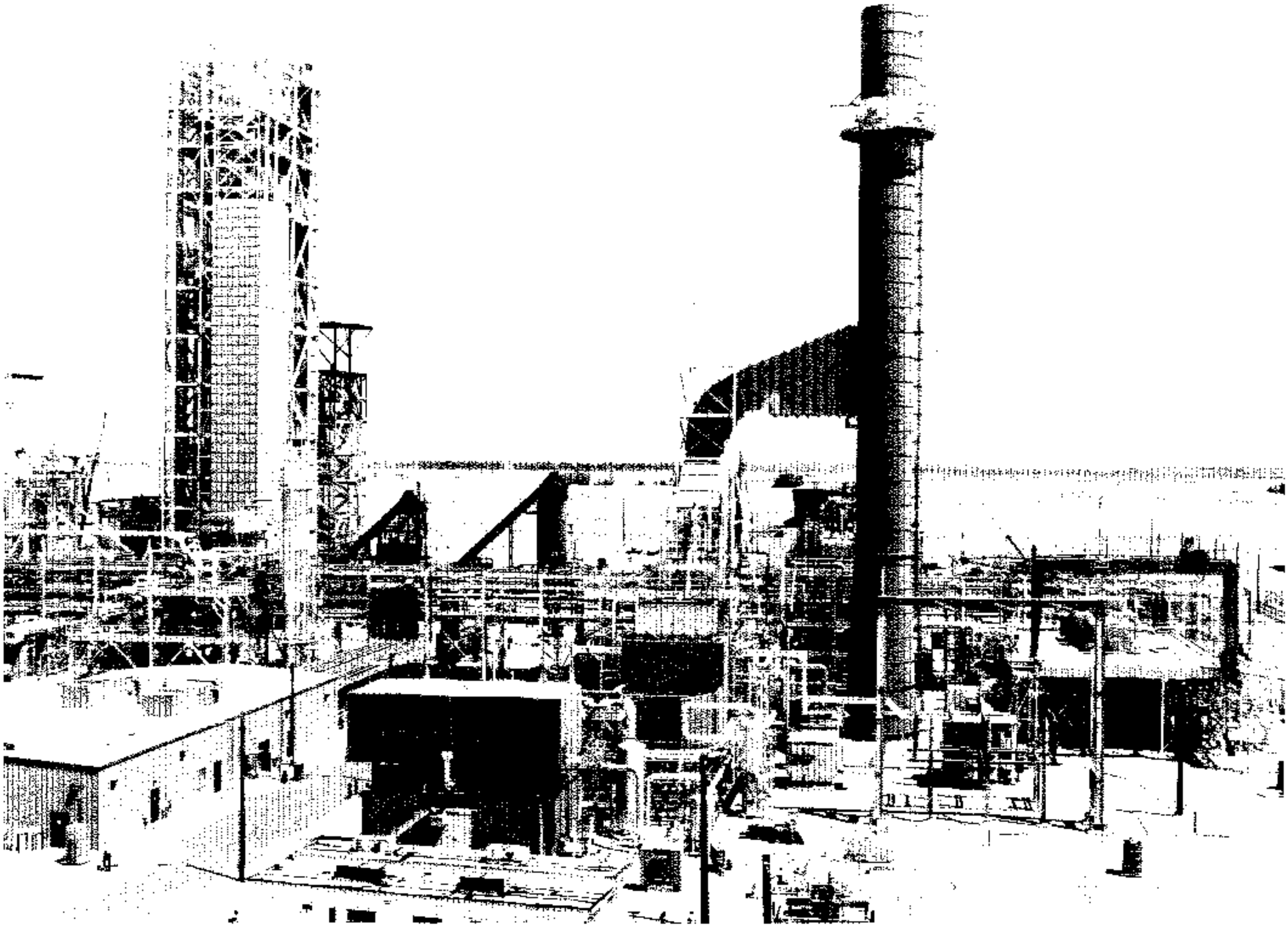
Harry O. Reinsch, president of Bechtel Power, reviewed some of the highlights of the Cool Water construction period, including fabrication, transport, and installation of the large gas cooling vessels. He said that successful completion of construction resulted from the spirit of cooperation among the project's partners and from good relations with the site's trade unions. The plant was completed within 50 months from start of design and 28 months from start of construction, which illustrates the potential of this technology for providing "quick response to regional needs."

The Japan Cool Water Program Partnership was represented at the dedication ceremonies by Kazuo Fujimori, chairman of its Board of Control and executive vice president of Tokyo Electric Power Co., the largest privately owned electric utility in the world. Speaking through an interpreter, Fujimori said that the decision of the various Japanese companies to participate had been vital and unprecedented and that completion of Cool Water had provided reassurance "that our decision was on the right track." In Japan the IGCC technology is being considered largely for meeting intermediate load, while nuclear power will remain more important for baseload.

At a press conference held just prior to the actual dedication ceremony, Dwain Spencer, EPRI vice president for the Advanced Power Systems Division, described to reporters the importance of Cool Water in the nation's overall energy development. "By using IGCC technology," he said, "we believe we can operate facilities with coal in as environmentally acceptable a manner as we do now with oil and gas. In particular, by demonstrating the acceptability of high-sulfur coals at Cool Water, we can reopen the opportunity for broad coal utilization in the midwestern and eastern United States."

Spencer also indicated that about 30 utilities have formed the Utility Coal Gasification Association to evaluate various coal gasification technologies and establish how they could best fit into future generation expansion plans. Most of the utilities involved in these studies are not planning to build new plants until about the mid 1990s, and after the Cool Water demonstration period, this technology should be a good candidate for decisions that will have to be made in the late 1980s. □

Combined-cycle power facilities of the new 100-MW Cool Water plant are a compact group, the exhaust stack flanked (at left) by the compressor air intake, combustion turbine, and heat recovery steam generator, and (at right) by the steam turbine, condenser, and gantry crane. Cooling towers are in the background, framed by the steam generator exhaust duct and stack.



improve process efficiency. Moisture is added to limit the combustion temperature, thereby suppressing nitrogen oxide formation.

Combustion of the clean syngas in a combustion turbine drives an electric generator that produces about 65 MW of power. The hot exhaust gases then pass to a heat recovery steam generator where further steam is raised and is superheated with the steam coming from the syngas coolers in preparation for driving a steam turbine. This turbine drives another electric generator to produce about 55 MW of power. Out of the approximately 120 MW of gross power thus produced at Cool Water, about 20 MW must be used to power the facility, including the air separation unit adjacent to the site, which provides the plant with oxygen and nitrogen. The net output on 230-kV lines to the SCE system is thus about 100 MW.

At present the slag collected at the bottom of the radiant syngas cooler is trucked to a nearby lined holding pond. One of the advantages of the IGCC process, however, is that this slag is basically inert. It has the appearance of black glassy pellets about the size and consistency of sand. The environmental safety of these pellets has been confirmed in pilot plant tests and will be further verified for this commercial-scale unit by tests at the holding pond and in the laboratory. The slag can then be easily disposed of or perhaps sold for use in making concrete or asphalt.

Bringing the plant on-line

No matter how confident engineers are in their designs or how smoothly construction has gone, everyone holds his breath when a facility as new as Cool Water first begins operation. To provide technical support for the critical startup period, EPRI sent Harris H. Gilman, engineering manager of the Advanced Power Systems Division, to work on-site. With long experience in petroleum and electric power, Gilman takes a highly personal view toward the plant. "It's uncanny," he says. "You can walk in there and not be able to tell if it's running. Every other plant I've worked on you could either hear it or see it or smell it and know whether it was going."

When asked about the startup, at first he just sighs. "It's a big job—a lot more complicated than you might think. Our good results to date reflect a conscious effort on everyone's part to work together. On paper, the organization is complex. It took a dedicated and cooperative attitude, and a lot of credit goes to the on-site program manager, Wayne Clark of Texaco."

A primary concern, Gilman remembers, was to establish a safety program that would take into account the novel combination of technologies. Utility personnel not accustomed to working with systems containing hydrocarbons and various gases, such as carbon monoxide and hydrogen sulfide, must learn some of the safety procedures commonplace in a refinery. To prepare SCE shift workers for both the new safety rules and the operating procedures of a new kind of power plant, training courses and the preparation of manuals began well before the startup period. Shift supervisors were trained first, and they taught the next group of workers under the surveillance of experienced instructors. The object, explains Gilman, was to "create teams, with each group learning from the ones ahead of them."

Despite careful preparation of both the plant and its workers, some problems occurred during startup. Heavier slag-handling equipment, for example, was needed, and a variety of valves, seals, and bearings, were changed. "In general these problems were fewer than those experienced in other first-of-a-kind plants EPRI has been involved in," comments Wolk.

This sense of satisfaction with the startup was echoed by Clark. "This is a large number of participants to deal with. But I've been extremely pleased with the quality of cooperation in the organization. Instead of being a problem, it's turned into a synergistic effort. Participants have given us their best people. We've been able to take the best of their ideas, put them together, and get fantastic results."

Test and demonstration

The job of quantifying just how well Cool Water is fulfilling its potential falls largely on the shoulders of the test and demonstration staff headed by John McDaniel, the EPRI project manager stationed at the site. "So far," he says, "the plant is working marvelously well." During September the facility was on-line 80% of the time. The capacity factor for the month, which accounts for occasional periods of operation below full-load rated capacity in addition to downtime, was 71%—surprisingly good for a new plant.

The test and demonstration team will be looking at both overall performance and several specific areas of technical uncertainty. Long-term reliability of the gasifier and syngas coolers represents the greatest unknown, because the rest of the plant involves equipment that is conventional in some industry. "All the data so far have been encouraging," McDaniel affirms. "We have a clear indication that the gasifier is doing better than its design specifications for coal conversion. The coolers are also performing better than expected."

Part of the uncertainty surrounding the gasifier involves the behavior of the ceramiclike bricks that form the refractory lining on its interior wall. This lining must be able to withstand both the heat of the gasification reaction and the abrasion of the passing coal and ash particles. The life expectancy of the refractory lining is a critical cost factor in the overall economic attractiveness of an IGCC plant, and McDaniel says that data so far indicate it will achieve the initial expected one-year lifetime before replacement.

Another critical uncertainty has been the possibility of fouling in the radiant syngas cooler. Slag solidifies during its 120-ft (36.6-m) fall through this cooler and at some point can become rather sticky. The principal concern was whether sticky particles of slag would adhere to the walls of the vessel midway down. Again, preliminary data indicate the presence of less fouling than had been anticipated.

Materials testing will be an important concern during the demonstration period so that future plants can optimize the choice of materials for various systems. Such testing is particularly important in an IGCC plant because many of the vessels will be subject to corrosion mechanisms in a reducing atmosphere different from those in the oxidizing atmosphere more common in steam-generating equipment. This difference results from the partial (or incomplete) oxidation of coal during the gasification process. In addition to resisting corrosion, some materials must also withstand the eroding effects of rapidly moving slag particles.

Some erosion-corrosion tests are being conducted by placing racks of coupons (small material specimens) directly in the process stream to determine the effects of long-term exposure. Other, larger material samples are mounted as an integral part of a piece of equipment, especially in the water-bearing portions of the syngas coolers. At critical points throughout the gas flow system, electrical probes have been inserted to measure the corrosive effect of the passing stream as a function of time.

One of the requirements that the SFC levied in return for syngas price supports was the establishment of a supplemental environmental monitoring plan (SEMP) as part of Cool Water operations. This plan involves more monitoring than would otherwise be required to establish compliance with federal and state regulations. Because of this additional monitoring, EPRI will not be as involved in conducting separate environmental testing as originally planned, but instead will concentrate on analyzing SEMP data in order to inform utilities about the environmental performance of the plant when it uses different coals.

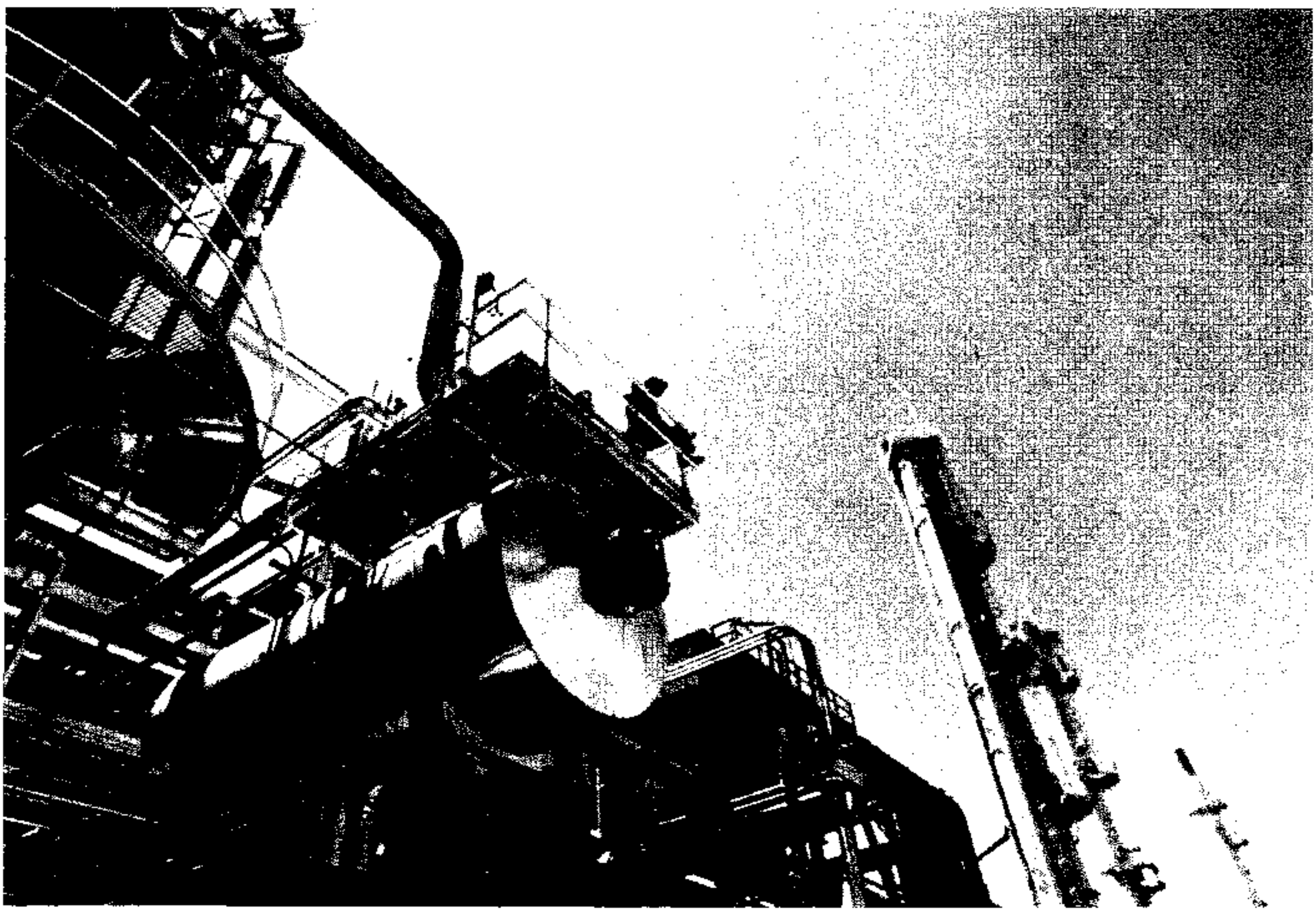
Each participant in Cool Water may choose a coal to be used in a sustained test at the plant. EPRI has chosen a high-sulfur eastern coal, Illinois No. 6, in order to answer several technical and environmental questions related to the immediate needs of member utilities. Eseerco chose another high-sulfur eastern coal, Pittsburgh No. 8 seam. IGCC technology shows great potential for using such coals, which are readily available to midwestern and eastern utilities that are facing increased environmental restrictions because of concerns over acid rain.

Future directions

To permit continued operation in the event the gasifier or syngas cooler requires unexpected maintenance, a spare gasifier is being added at Cool Water. This quench gasifier will not have the complex gas coolers used to recover excess heat for making steam but will douse the gas with water to cool it and solidify the slag. Although the IGCC system will run at lower efficiency in the quench mode, the spare can be built at a much lower cost and will help increase overall plant availability. The quench gasifier is expected to be ready for operation in March 1985.

Although IGCC is being considered mainly as a baseload option, future tests will be conducted at Cool Water to determine the plant's load-following capabilities. An advantage of the Texaco gasification process is that it responds almost instantaneously to changes in slurry input, compared with a much slower response from gasifiers that hold materials for longer periods of time. Because the overall plant is highly automated with microprocessor controls of critical functions, it is anticipated that load following from at least 50% to full load for each individual gasifier will be no problem and that future IGCC facilities might be used for intermediate-load applications.

Since startup the Cool Water plant has generally been operating at a net heat rate of about 11,500 Btu/kWh, compared with an initial design rate of 11,300 Btu/kWh. A scheduled maintenance period in October was expected to correct deficiencies to reduce the operating heat rate (and thus raise plant efficiency) to levels closer to design specifications. In addition, plant engineers hope that future changes, including an increase in



Effluent and emission control systems at Cool Water include process water treatment (left) and a Selexol unit (right) to remove sulfur from the syngas in the form of hydrogen sulfide.

Cool Water at a Glance

Capital Cost	$263 million
Construction time	28 months
Coal throughput	1000 t/d
Plant power rating	120 MW
Combustion turbine	65 MW
Steam turbine	55 MW
Power utilization	
Net to utility system	100 MW
Auxiliaries and air separation	20 MW
Heat rate*	
Initial target	11,300 Btu/kWh
Ultimate goal	10,600 Btu/kWh
Capacity factor	
1984 target (cumulative)	25%
1984 actual (through October 31)	30%
Best month (September)	71%
Operations through October 31, 1984	
Coal consumption	65,000 t
Gasifier operation	1600 h
Gross power production	138 million kWh

*For a larger, commercial IGCC design, the projected heat rate is 9000 Btu/kWh.

slurry concentration and a reduction in oxygen purity, may bring the heat rate down to about 10,600 Btu/kWh.

It should be noted that certain efficiency-improving features were not incorporated at Cool Water because of the plant's relatively small scale and its first-of-a-kind nature. In a larger commercial IGCC plant operating under improved conditions and employing a more efficient reheat steam turbine, a heat rate of approximately 9700 Btu/kWh is projected, comparable to that of a conventional coal plant with stack gas scrubbers. Introduction of a new model combustion turbine planned for the late 1980s and designed for a higher firing temperature should result in a further improvement to about 9000 Btu/kWh. Studies are also under way to quantify the benefits of phased construction for IGCC plants, such as building the power generation part first and letting it enter the rate base with petroleum or natural gas before adding a coal gasification section.

"This is the first fundamentally new technology for making electricity from coal since the 1920s," says Seymour Alpert, technical director of fuels in the Advanced Power Systems Division. "It also represents a new business opportunity for utilities because the syngas could be marketed as feedstock for chemical companies near an IGCC plant.

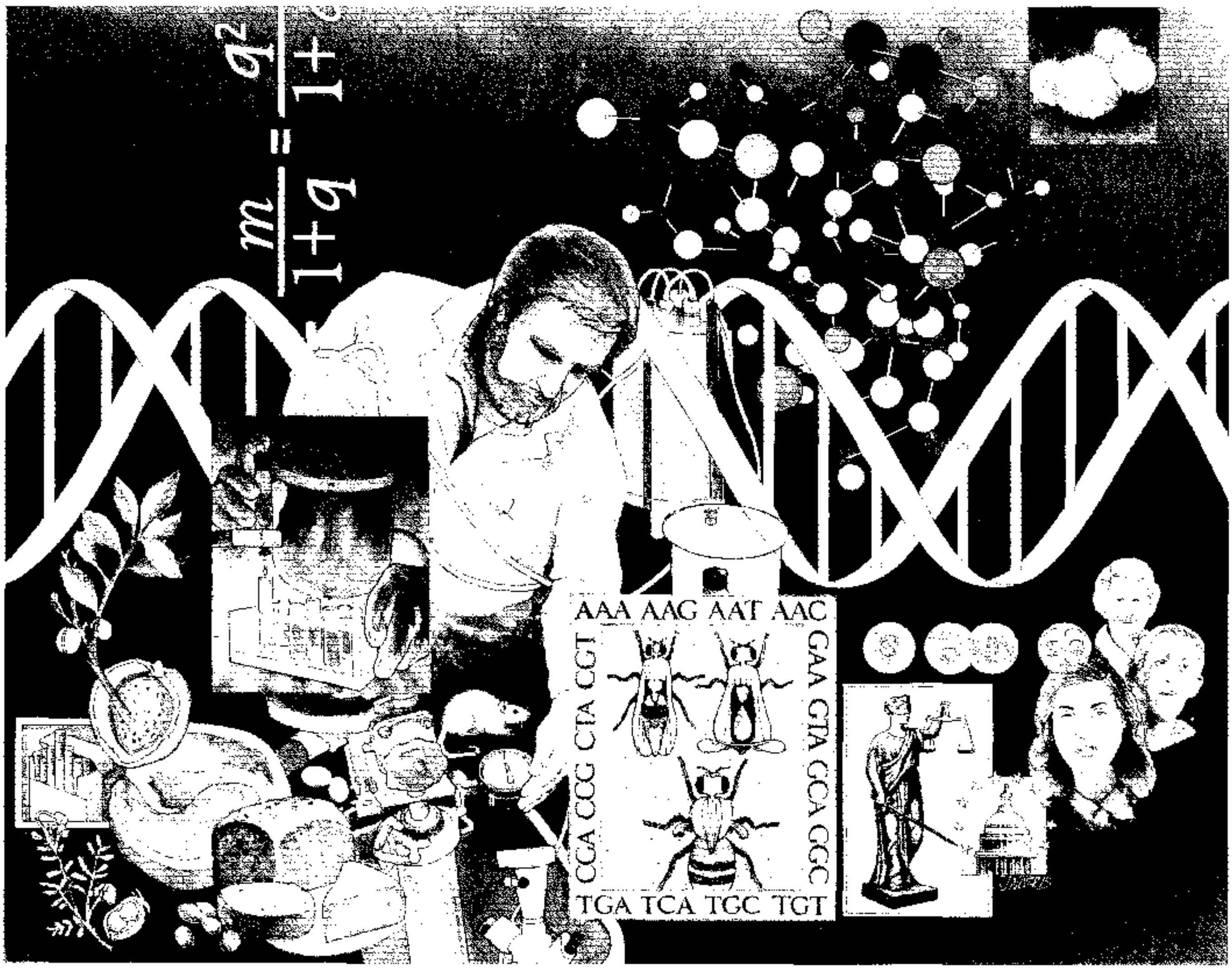
"Cool Water is a building block," he continues. "We're showing that small baseload plants, with perhaps 250-MW capacity, could be put on-line in about two or two-and-a-half years. Some 15–20 utilities are now actively considering this technology, and if all goes well at Cool Water, I wouldn't be surprised to see the first orders for commercial IGCC plants in a couple of years. We have a real sense of excitement over this plant; it's a spirit of pioneering."

This article was written by John Douglas, science writer. Technical background information was provided by Thomas O'Shea, John McDaniel, and Harris H. Gilman, Advanced Power Systems Division.

by Brent Barker

Cancer and the Problems of Risk Assessment

The question of how to quantify and communicate risk in the modern world has great implications for public acceptance of science and industry. The latest meeting of EPRI's Advisory Council, featuring talks by nine experts in the field, used cancer as a focus to dissect the difficulties of risk analysis.



Conventional wisdom 25 years ago held that cancer-causing substances were rare and ultimately controllable, that the sources of the disease would someday be isolated and eradicated. The model was not unlike that of many large communicable diseases that had been brought under control by twentieth-century medicine. But as scientific exploration advanced through the 1960s and 1970s, the known and suspected sources of cancer expanded rather than narrowed, and the mechanisms of the disease grew more complex rather than more simple.

As headlines bannered each newly discovered cancer-causing compound—in what became known cynically as the carcinogen of the week—the old hope gave way to fear and fear to mounting pressure on the political and legal systems for protection and compensation. Eventually, ideology began to suffuse fact in an interpretive scramble to replace simple cause with simple blame, and by the mid 1970s industry was popularly indicted. It seemed a fitting notion to a society newly infatuated with things natural that it would be the things synthetic that would cause cancer.

Today, conventional wisdom inclines toward the belief that cancer, like a case of the disease itself, is growing out of control, perhaps even heading toward epidemic proportions and that it is all fundamentally due to new risks imposed by our industrial base, risks resulting from our post–WW II profusion of man-made chemicals, pesticides, plastics, food additives, radiation sources, and the like.

Although science in recent years has acquired new information that promises once again to turn conventional wisdom upside down, the deep dread of cancer, combined with its presumed link to industry, has brought about an explosive public health issue, one in which enormous social forces are now being unleashed. For all practical purposes the courts and the regulatory bodies are now under siege, and the liability issues threaten to drain the resources of producers and insurers alike.

It was against this backdrop that the EPRI Advisory Council drew together 50 participants from industry, government, and universities to discuss the interdisciplinary nature of technology risk assessment and, in particular, to focus on the critical issues surrounding cancer risk from exposure to toxic substances.

Although the utility industry is not at the center of this storm, it does have a broad interest in the development of risk assessment methodology. And because cancer embodies virtually all the societal concerns over risk in the modern world, it was considered by the meeting organizers to be a useful focal point for illuminating the larger sphere of risk assessment.

Bruce Ames

"Nature is not benign. It's full of nasty things. There are large numbers of carcinogens and mutagens in every meal, all perfectly natural and traditional. My own estimate is that we eat about 10,000 times more of these natural pesticides than we do of man-made pesticides."

At the Hyatt Del Monte in Monterey, California, nine invited speakers led off the three days of vigorous exchange on the scientific knowledge of cancer risk, the legal and societal response to risk, and risk management policy. Time and again the discussion returned to the emerging field of quantitative risk assessment, with the participants in clear agreement that not only do the numbers matter (given the enormous range in both carcinogenic potency and exposure), but the numbers themselves will someday lead to and support new language for communicating the broad spectrum of risk to the general public. Currently, the public has no frame of reference, and so when confronted with a new carcinogen, it cannot separate a significant risk from a trivial risk.

Cancer risk in perspective

Bruce Ames, chairman of the biochemistry department of the University of California at Berkeley, lent some much-needed perspective to the area of cancer risk by dispelling the myth of an ongoing epidemic and by summarizing some critical new information about natural carcinogens, the role of diet and metabolism in cancer, the human defense mechanisms, and a possible link with aging.

One out of four in the United States now dies of cancer, and when the historical statistics are adjusted for the increasing longevity of the U.S. population, the same was apparently true 50 years ago. With the exception of lung cancer, which has clearly increased because of cigarette smoking, cancer rates have held constant or have declined over the last 5 decades. "This strongly suggests that whatever is causing cancer has been around a long time," said Ames, "and the epidemiologic work by R. Doll and R. Peto indicates that our industrial pollution doesn't play a major role, probably less than a few percent." He went on to say that because cancer rates by type vary from culture to culture (Japanese are relatively higher in stomach cancer and Americans in colon and breast cancer), environmental factors in the broadest sense became suspect and, after considerable searching, narrowed down to what should have been obvious from the beginning: the human diet.

Ames recalled that Sugimura in Japan, knowing about the mutagenicity of cigarette tar, made a mental connection, scraped some brown and charred material from the fish cooking on his grill, used a quick bioassay test, and found it highly mutagenic (and presumably carcinogenic). Subsequent work in Japan and the United States revealed that virtually all burnt and browned material contains carcinogens—from auto exhaust to cooked protein to coffee to caramelized sugar—and that it is through the diet that the greatest quantities are normally ingested. Ames indicated, for example, that the daily intake of burnt and browned material from cooked foods is typically several times greater than that taken in by a heavy smoker, although it could well be that the lungs are more sensitive to carcinogenic material than the stomach.

Plants, another staple of the human diet, are also filled with mutagens and carcinogens. Without the ability to run from predators, plants have evolved a form of chemical warfare to ward off fungi, insects, and the like. Ames pointed out that plants are 2–10% by weight toxic chemicals and cited a lengthy list of compounds found in ordinary foods, from black pepper and mustard to mushrooms, celery, and some herbal teas, whose natural pesticides are known carcinogens. One additional wrinkle of the plant's protective mechanism is that when damaged or bruised, it increases its toxic output (of the same or different chemicals), often by 100 times or more. "Nature is not benign," said Ames, "It's full of nasty things. There are large numbers of carcinogens and mutagens in every meal, all perfectly natural and traditional. My own estimate is that we eat about 10,000 times more of these natural pesticides than we do of man-made pesticides."

Protecting us from this carcinogenic onslaught, which extends beyond our food to chemicals of all types and even to sunlight and oxygen, is an elaborate three-tiered defense. The first defense is that "we are partially disposable . . . every day we slough off the lining of our mouth, stomach, colon, intestine." The second line of defense is biochemical, an elaborate system of enzymes, designed principally to counteract the effects of toxic substances. Here the diet plays a vital role in supplying so-called anticarcinogens, such as beta-carotene, vitamin E, and selenium. The third line of defense occurs after the first two are breached and some of the damage is done: repair enzymes run up and down the DNA helix looking for damage and snipping out the damaged part. Some enzymes repair any break they encounter, others are coded to look only for a specific (and presumably very important) type of damage. But the onslaught is enormous. On the basis of his analysis of the discards of repaired-out DNA in the urine, Ames estimated that "thousands of hits are made on the DNA of each cell every day."

Jeffrey Harris

"Can we screen all these chemicals, and what are the implications of doing so? Being compelled to assess chemicals on a case-by-case basis, forward risk assessment operates in a world where false positives [falsely indicated cancer] or trivial true positives can have large social costs."

How then, given this flux of genetic damage, have we managed to survive at all? Undoubtedly, the body's defense mechanisms are of major importance. Ames believes that although the full answer still lies before us, through the use of recombinant-DNA tools science is crossing a new threshold of understanding and that the causes of the major human cancers will be understood in the next decade. "Biology is going like a rocket," he said, "and things are going to turn out to be very different from what people think." He finds particularly intriguing that aspect of cancer that may be bound up with the aging process, and believes that "a big contribution to cancer will turn out to be our own metabolism."

In this regard, one innovation during primate evolution that probably helped us evolve from a short-lived to a long-lived creature was a slower metabolic rate (rats, for example, with a much faster metabolic rate, begin to succumb to tumors after 2 to 3 years, just as humans do in their 70s and 80s). By reducing the metabolic rate we reduce oxygen intake and in turn the flux of so-called oxygen radicals, which Ames thinks could be an important contributor to both cancer and aging. With free electrons available, these radicals bond to and damage DNA; thus, oxidation, which causes fats to go rancid and metals to rust, appears to be a fundamental destructive process in human beings as well. We breathe in 21,000 liters of air each day, and as the oxygen accepts electrons in the formation of water, it goes through several intermediary stages (hydrogen peroxide, hydroxyl radicals) that are known mutagenic and carcinogenic compounds.

What Ames has succeeded in painting could be thought of as our natural carcinogenic background against which newly found carcinogenic risks can and should be compared. He points out that nature's pesticides typically come in parts-per-hundred or parts-per-thousand concentrations and impose measurably greater risks than the parts-per-billion controversies that have characterized some of the great public scares in recent years, such as ethyl dibromide (EDB) in grain products and trichloroethylene in the well water of Silicon Valley (California). Both of these he claims are less risky in terms of carcinogenesis than drinking a glass of ordinary tap water (because of chloroform from chlorination) or eating a peanut butter sandwich (because of aflatoxin). Such risks typically cannot be separated from the carcinogenic background and are trivial compared with such things as cigarette smoking, which accounts for 30% of cancer deaths in the United States as well as 25% of fatal heart attacks.

Defining and measuring the link

Many people die of cancer, and the fact that there are tens of thousands of potential cancer-causing agents (including our own metabolism) makes the linkage between a specific cancer and a specific exposure highly tenuous. At best it comes down to a probability surrounded by some carefully crafted measure of uncertainty; at worst, just someone's guess. Some diseases, such as asbestosis, have such a unique symptomatic signature that the probability of causation approaches 100%; but with most cancers the source could be any one of thousands of possible carcinogens.

Compounding the problem of pinpointing a specific cause are the long latency of most cancers (20–30 years), during which many other exposures and stresses take place; the amplification of cancer risk by multiple agents (e.g., asbestos plus smoking, or smoking plus drinking); and the possibility that cancer is not just an either/or disease but rather a progression through several distinct stages, with each stage requiring its own initiator or cause (the so-called multistage model).

Despite the complexities, it is the business of the risk assessment field to extract the factual basis of such risk, to seek proper definition of the risk, and, if possible, to put a number to it. In the elusive world of cancer causation, the traditional methods of gathering facts have been epidemiologic studies, which look for the statistical differences in human populations, and animal studies in controlled laboratory tests. Both are slow and expensive. Animal studies, for example, now cost about $500,000 for each chemical tested, can take years, and can introduce great uncertainty when the results are finally extrapolated from rats to human beings.

As a result, risk estimates are less than precise, and relatively few chemicals have been tested for carcinogenicity in animals. In 8 years, the National Cancer Institute and the National Toxicology Program have only tested some 200 compounds, the bulk of which were man-made chemicals. About 10 years ago, another fundamental tool, the short-term bioassay test, was added. This allows for a quick (48-hour) test of mutagenicity by counting bacterial colonies in a Petri dish. Sometimes referred to as the Ames test after its pioneer, the procedure has vastly expanded the ability of science to explore the toxicity of the real world. Over 3000 laboratories in the world are now using the Ames test and other short-term bioassays.


Warner North

"How can we develop a process that the public can trust? We can bring together the best of science in risk assessment but we are still left with a range of uncertainty, debate, and disagreement, and then critical concepts get lost when a number goes in a public document. I think there is real danger in one seemingly blessed number ending up in a report."

Jeffrey Harris, M.D., associate professor of economics at MIT, addressed the strengths and weaknesses of the field (and its tools) by dividing risk assessment into two basic approaches: forward (e.g., laboratory) and backward (e.g., epidemiology). "In forward risk assessment, we start with a large collection of potentially carcinogenic agents and try to determine which ones cause cancer, and if so, how much cancer. . . . Here we are supposed to find an efficient means of reducing 10,000 potentially carcinogenic agents to perhaps a few dozen important ones. Can we screen all these chemicals, and what are the implications of doing so? Being compelled to assess chemicals on a case-by-case basis, forward risk assessment operates in a world where false positives [falsely indicated cancer] or trivial true positives can have large social costs." Given the charged atmosphere surrounding anything labeled cancer-causing, the danger Harris sees is that forward risk assessment can send us off on some very expensive goose chases, reacting to everything that shows up positive in a laboratory.

"In backward risk assessment," said Harris, "we start with a large collection of cancer cases and try to determine what caused them. . . . The data are poor, difficult to collect, and only gross truths come out. But the main benefit of looking at the human experience and working backward is that interesting hypotheses are formed that are not created by moving forward. We observe, for example, that the most significant trend in cancer incidence is the marked, continuing rise in lung cancer, especially that now occurring among women. . . . We also see that while the incidence of breast cancer in Japan is relatively low, the rate among Japanese women who migrate to Hawaii is four times greater—that is, much closer to the breast cancer rate among Hawaiian whites."

Harris believes that despite its bad reputation, epidemiology is an important tool and one vastly underused. He sees its real significance as providing major clues, new ideas, and above all, the big picture. It was, after all, backward risk assessment techniques that established and defined the risks of radiation, tobacco, and asbestos.

Nevertheless, the shortcomings and scientific frustrations of the risk assessment field drew fire throughout the three-day conference. Karim Ahmed, senior scientist and research director for the Natural Resources Defense Council, said, "I'm skeptical of quantitative risk assessment, at least in the cancer field. The science is too imperfect, and the results are likely to be used literally, because all the caveats get lost."

Warner North, principal of Decision Focus, Inc., expressed similar concern about how to meaningfully convey the uncertainty surrounding quantitative risk assessments. "I'm awed," he said, "by the magnitude of the problem facing us. How can we develop a process that the public can trust? We can bring together the best of science in risk assessment, but we are still left with a range of uncertainty, debate, and disagreement; and then critical concepts, such as plausible upper bound, get lost when a number goes into a public document. I think there is real danger in one seemingly blessed number ending up in a report."

The uncertainty in risk estimates stems in part from using animals as surrogates for humans, because there can be orders of magnitude difference in the carcinogenic potency of a given substance among different species. And it was in this vein that Laurence Moss, a consultant with Energy Design and Analysis, Inc., recalled the different reactions to unleaded gasoline, and asked facetiously "whether a man is more like a mouse or more like a rat." North responded, "The issue is, in fact, crucial because it makes a great deal of difference in the estimate we get. One of the worst-case assumptions built into the EPA procedures is that they use the most sensitive species, and there are situations where we have reason to believe that the most sensitive species may not be representative of the way the human metabolism works."

Milton Russell, assistant administrator for policy, planning, and evaluation at EPA, added that "depending on which animal you use, and whether you use a model that uses surface area or weight, you can get a difference in risk of up to 39,000 times." He went on to add that uncertainties in the risk assessment process are multiplied (not added) and in the case of cancer risk this leads to extreme conservatism in the decision-making process. "If you are relatively sure of the probability of risk, like automobile accidents, the range of uncertainty is narrow, and the difference between a plausible upper bound and a maximum likelihood and a plausible lower bound is relatively small. But if you are quite uncertain (as we are in many of these health effects), the range between this upper and lower bound is very, very large. Multiplying the large uncertainties associated with each factor in the estimate leads to cascading conservatism in decision making."


William Thilly

"Each mutagen leaves a recognizable fingerprint, a unique pattern of mutation on the DNA of the cell population that we can read. We think we're close to developing the technology that permits this analysis on a single blood sample."

Reflecting on the various dilemmas of cancer risk assessment, including the impossibility of ever proving that something is not a carcinogen, Arthur Upton, professor at the New York University School of Medicine and former director of the National Cancer Institute, said, "Epidemiologic evidence is long in coming and relatively insensitive. And animal systems are not altogether predictive: We know that the rat only predicts the mouse 80% of the time and vice versa, and that the rodent may miss an important human carcinogen altogether." Ahmed added, "Major uncertainties arise not only from animal-to-human extrapolations but also from the different theoretical cancer models assumed in the estimates." And Alvin Weinberg, director of the Institute of Energy Analysis of Oak Ridge Associated Universities, concluded, "We may be dealing with issues that transcend today's science."

Given its lack of precision, Chauncey Starr, vice chairman and founding president of EPRI, suggested that quantitative risk assessment be viewed as much as a process for clarifying thought and ensuring dialogue as for any particular number it might produce. "It forces full disclosure of assumptions, precepts, and biases of all parties to the process," he said. "It also reveals all secondary interactions, including the benefits derived from taking a technological risk, so that we end up with the most rational means of allocating public resources. . . . We must be patient with the process, recognizing that we are in the infancy of an art. Quantitative risk assessment will improve with time; right now it's just a rough guide but still better than someone's guesswork."

One thing that may come with time, perhaps even in the next few years, is a powerful new tool for risk assessment, one that might reduce the uncertainties by providing direct access to the human beings at risk. William Thilly, professor of genetic toxicology at MIT, believes that indirect, subjunctive means of estimating hazards, such as animal models or cell assays, will not be sufficient. Instead, he proposes developing techniques that have the capability of directly measuring (through the blood or urine) genetic damage in humans resulting from some exposure to agents that react with and change human genetic material. He and his colleagues at MIT have found that each chemical mutagen causes genetic change in human cells grown in a laboratory in precise, unique, and repeatable ways. For the last year they have been trying to develop a molecular recognition technique (denaturing gel electrophoresis) to get at these patterns in human blood samples. Said Thilly, "Each mutagen leaves a recognizable fingerprint, a unique pattern of mutation on the DNA of the cell population that we can read. We think we're close to developing the technology that permits this analysis on a single blood sample. Our goal, which we believe to be wholly feasible, is to be able to differentiate chemically induced changes from spontaneous changes. The method should be applicable to identifying major chemical mutagens should it be discovered that cells in humans suffer predominantly nonspontaneous changes."

A direct measurement tool, such as Thilly's work promises, could not come at a more opportune time. It may help to tighten the cause and effect linkage at a time when court cases are mushrooming; to refute false claims of damage; to allay the mental distress of exposed populations; and to give risk assessment a sounder footing in future policy analysis, compensation and litigation actions, as well as in the business of allocating scarce public health resources. It comes at a time of mounting public fear and pressure, at a time when the federal government, for example, has just embarked on a full-scale investigation of the effects of Agent Orange that will cost $100 million and run through the end of the century.

Although physical effects on the Vietnam veterans or their offspring have not yet emerged, anxiety has emerged as a fundamental driving force. The *New York Times* recently cited a University of Minnesota study (Korgeski and Leon) that found the uncertainties of Agent Orange exposure produced psychological problems akin to those of survivors of atomic explosions.

Legal and political solutions

How will society respond to these newly discovered, newly perceived, and newly disputed risks? One clear trend is to move them into the courts, and Sheila Birnbaum, associate dean and professor at the New York University School of Law, said, "Given the dramatic increase in the number of claims arising from exposure to toxic substances, I wonder whether the legal system as we know it can respond. . . . There are thousands of claimants instituting action as a result of exposure to hazardous waste leaking from disposal sites, such as Love Canal and Times Beach. The potential class members in the Agent Orange case may be in the tens of thousands. Eight thousand claimants have joined in one suit for alleged injuries from exposure to DDT in northern Alabama. And asbestos certainly ranks as one of the most momentous problems in the U.S. courts: 24,000 claimants through March 1983, with 75,000 to 240,000 potential claimants; over $1 billion paid out between 1970 and 1982; a national class action now forming in Philadelphia, with the potential for sweeping in thousands of school districts; and beyond that there are 800,000 public buildings to be inspected."

Sheila Birnbaum

"Given the dramatic increase in the number of claims arising from exposure to toxic substances, I wonder whether the legal system as we know it can respond. . . . How can we design a system that will not stifle innovation, be efficient, nonbankrupting, and still compensate?"

Toxic tort litigation, according to Birnbaum, is presenting the legal system with some new issues, ones that she thinks will take perhaps a decade to work out. First, there are large numbers of plaintiffs, and in the case of generic products, perhaps thousands of plaintiffs suing hundreds of companies. Second, there are new kinds of injuries, injuries that may take 5–30 years to show up, perhaps well after the statute of limitations has run out (e.g., New York State barred the Brooklyn shipyard workers who were exposed to asbestos in the 1940s from filing claims). Third, there is the difficulty of establishing a causal link between the plaintiffs' injuries and the substance produced by the defendants.

In the way of movement toward resolving these issues, Birnbaum said, "I think we are beginning to see a judicial trend toward providing funds for long-term medical monitoring of a population exposed to hazardous substances. Further, some legislators are proposing some type of modified no-fault system, where the first recourse is to an administrative system that would provide a sliding scale for compensation and put a cap on damage awards, much like workmen's compensation. Only after that would there be recourse to the courts."

On a more philosophic plane, she added, "Regarding future injury, we are at a real legal crossroads: Should we give an award today for possible damage 20 years down the road? Or should we modify statutes of limitation to allow awards to those actually injured 20 years from now? How can we design a system that will not stifle innovation, be efficient, nonbankrupting, and still compensate?"

The legal issues drew some of the greatest heat of the conference. Floyd Culler, president of EPRI, weighed in, "I can't imagine paying for risk. Where would it stop? For that matter, where would it begin?" Ames, following this logic said, "Ordinary mustard has a carcinogen in it. Can these people sue the mustard manufacturers? Should we compensate people for eating mustard?" And Michael Gough, senior associate with the Office of Technology Assessment, held out for compassion as a guideline for reason. "People whose children suffer birth defects should get more than people with sleepless nights from worry." Birnbaum agreed that "anxiety is fraught with false claims, and if we as a society pay, we encourage worry."

Toxic torts has become big business, and many participants singled out greed as a real driving force behind the rush to the courts. Most of the ire was directed at the legal profession, who, in the case of the asbestos awards, have walked away with sixty cents on the dollar. Peter Huber, law clerk with the U.S. Supreme Court, added, "This ignores the cost of the courts themselves, the bureaucracies, the larger legal machinery. The laws of risk have become grossly disconnected from science, and partly because the business is so tremendously lucrative." As if to add insult to injury, Birnbaum noted that foreign plaintiffs, unable to collect in their own countries, are now coming to the United States for recovery.

The regulatory role

Regulatory agencies, not unlike the courts, have become lightning rods for public dissension over technological risk. Russell characterizes EPA as a product of three forces: law, science, and public pressure. "We're not philosopher-kings who can sit aside in an ivory tower. We must act under the law, that is, under 12 major statutes passed by Congress under different circumstances, with different motivations, and with different ends in view. Some of these statutes, such as the Toxic Substances Control Act, allow us to balance risks, to weigh the costs and benefits of alternatives, and to come to some reasoned decision. But others, such as part of the Clean Air Act, have no risk-balancing provisions and they say, in effect, that we should have zero risk, which is clearly impossible.

"So we need some flexibility to operate. But now the mood of the country and the mood of Congress is to eliminate all that flexibility. We have, for example, 300 past and current statutory deadlines, many of which are simply impossible for us to meet in terms of getting the science done, getting the work done, and putting it together. As a result, we are constantly in violation of the law, and anybody can sue us. And when they do, any judge who wishes to do so can find reason on behalf of the plaintiff to set us off on a court-ordered schedule. So we now find ourselves constantly working on somebody else's agenda and redirecting our resources to the next court-ordered deadline."

Milton Russell

"The EPA is a product of three forces: law, science, and public pressure. We're not philosopher-kings who can sit aside in an ivory tower. We must act under the law, that is, under 12 major statutes passed by Congress under different circumstances, with different motivations, and with different ends in view."

The whipsaw comes not just from court action. Just how quickly the contagion of fear can turn about the agency's attention and resources was evident in the EDB case. Russell said, "Despite the lack of clear scientific evidence defining the magnitude of public risk, we were suddenly facing a firestorm of protest around the country. State after state was adopting nondetect levels or one-part-per-billion levels as far as food was concerned, and we were heading, through panic, ignorance, and serious concern, toward the possible disturbance of a sizable fraction of the nation's food supply. We were forced under those circumstances to act, and now we are having to move as rapidly as we can to examine the risks of alternative fumigants and pesticides."

To a nation beset with fear and splintered by special interests, the reality of limited public health resources is becoming harder to grasp or at least to accept. Averting one risk may well mean pulling resources away from another risk where the public health dollars can save more lives. Addressing this dilemma, Merril Eisenbud, director of the Laboratory for Environmental Studies at New York University Medical Center, said, "I wish we could somehow achieve a national consensus on what constitutes trivial risk so we could avoid diverting scarce public health funds. Let me give an example of a plant producing elemental phosphorus. It turns out that the radium in the phosphate rock was being converted in the process to polonium 210, which came off the stack and posed a small risk to the residents 80 kilometers downwind. The Office of Radiation Programs recommended that a special scrubber be installed that would avert 0.01 cancer deaths per year, or 1 per 100 years, at an equivalent cost of $200-$300 million dollars. Now people in the public health field are not accustomed to spending $200 million to avert one case of anything. I remind you that the total cost of the U.S. measles eradication program was less than $100 million dollars."

Russell responded that because of the public and statutory realities now facing EPA and requiring it to take action, "we have been presented with serious proposals to take risk-reduction actions in the neighborhood of $200 million per life saved." He said he believed the real reason this was occurring was that the two models of health care in the world today, the private physician model and the public health model, were being confused. "When I go to my doctor, I'm looking for individual care. I want my physician to be my advocate, and I'm not interested in hearing that somebody across town could make better use of the medical facilities than I could. Unfortunately, this private physician model—where alternative uses of resources are not considered—is now being carried over to public health."

Perceptions and politics

With the courts clogged and the health agencies overwhelmed, public opinion and political process were of keen interest to the participants. How is public opinion on matters of risk being formed? And what role does science play in the public appraisal of risk? Stanley Rothman, professor of government at Smith College, suggested some fundamental shifts have been occurring, including "a loss of authority of the scientific establishment over the last 15 to 20 years on issues of risk; the loss of trust in scientists associated with business; and the growth of a plethora of public interest groups that have a relatively high level of credibility with the public on matters of technology and risk."

Stanley York, commissioner on the Wisconsin Public Service Commission, laid out three elements of what he called political reality affecting risk decision making. "First, the public believes that it understands the technical issues of carcinogens and nuclear power as well as anybody at this table because they have read about them in the newspaper. Second, each new study (of carcinogens) proves to the public anew that those who are making the product under discussion are indeed evil people. Third, inflammatory issues are the lifeblood of some interest groups; they will not survive without them."

Rothman takes the point even further. From data gathered in his large-scale study of social leadership in the United States, he concluded, "Political ideology has played a significant role in changing the American perception of risk over the last 20 years. To put it bluntly, some are using risk as a surrogate to attack the economic and political system of the United States."

Rothman's work to date has concentrated on attitudes toward nuclear power, but he believes that as he progresses into the area of carcinogens the basic tenets will hold up. One that he found was a strong left-right ideology dimension to the perception of nuclear safety. He examined a large number of social variables (e.g., age, sex) to explain the wide range in safety estimates, and found the only factor that correlated highly with the belief in the safety of nuclear plants is political ideology. The more liberal (or left) an individual, the more likely he or she is to believe that nuclear plants are unsafe.


Stanley Rothman

"Political ideology has played a significant role in the changing American perception of risk over the last 20 years. To put it bluntly, some are using risk as a surrogate to attack the economic and political system of the United States."

Another key finding Rothman addressed is that the public believes the scientific community is deeply divided in their opinions about nuclear power. Sixty percent of the public, for example, believe that scientists are evenly split on matters of nuclear energy, whereas he found a strong consensus among scientists that nuclear power is safe. Among individuals in the 71 disciplines in his energy expert sample, he found 88% believe nuclear plants to be safe; and among nuclear energy experts, defined broadly enough to include radiologic health and radiation genetics, he found 91% believe nuclear plants to be safe.

Rothman suggests that the public receives improper signals on the extent and nature of disagreement among scientists through the concentration of the media on the scientific minority who are political activists, those who are more inclined to speak directly to the public on matters outside of their specialty. "Traditional scientists," Rothman says, "generally don't communicate with the public. They tend to avoid public controversy because they dislike messy emotional relationships and they find it difficult to refute charges of possible disaster."

Chastising his fellow scientists on this point, Don Ritter, congressman from Pennsylvania, said, "The fray has entered the highest levels of American politics, and there is indeed a left-right breakdown on these issues. If the values of science are off on the sidelines watching, and only the values of the activists are entered into the debate, we're not going to get a balanced decision."

Ahmed rejoined this line of discussion saying he did not believe that environmental groups have had disproportionate influence in the political process, and he cautioned against the temptation to stereotype: "Environmentalists do not have a single voice. There are many different points of view, and we are not trying to do industry in. Environmentalists are not crazies. We are more than willing to make trade-offs."

Edward Larkin, commissioner with the New York Public Service Commission, observed, "What really divides us,

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here and elsewhere, what frustrates us, what prevents effective action, is the conflict of specialization and special interest. The economist, the scientists of every kind—everybody has his own narrow focus, and everybody thinks his is the most important. We don't deal in overall solutions."

Toward a new language

Quantitative risk assessment seemed to offer the participants the best hope of reaching common ground, of integrating the work of various specialists, and of putting risks into perspective. But can that perspective be communicated broadly? Walter Marshall, chairman of the Central Electricity Generating Board in the United Kingdom, remarked, "There is a third element needed, one between risk assessment and risk management, and that is presentation, the obligation to present the risk in terms that people can understand."

A new language is needed that converts probabilistic risk assessment, with its notions of chance, into meaningful terms, and several participants offered some images for starters. North said, "We must get away from the black-and-white notions that something is either a carcinogen or it is not. I would suggest a traffic light model with red, green, and blinking amber—where we have grounds for suspicion but not enough for regulation." And Marshall offered the analogy of "one puff per Sunday. The risk you take if you smoke one-twentieth of one cigarette every Sunday is less than that of involuntary smoking, or that of one rem of radiation to each of 10 million people, or that of breathing gasoline vapors while filling up your own car once a week."

Broad public understanding was never more important, because new forms of information are likely to be put into the public forum. Upton reminded everyone that "a bill was just passed that requires the Secretary of Health and Human Services to provide Congress with a report that would include a series of tables specifying in precise numbers the probability that a cancer arising in an irradiated individual resulted from the radiation exposure, ranging from a millirad to a thousand rads. This obviously goes way beyond the science we have today. We don't know if a millirad will do anything; we don't know that a rem will do anything. But this set of tables is being produced and will be available to the public soon."

The question is not whether quantification of risk is desirable; both the public and the experts largely agree that hard numbers offer the best tool for evaluating risks and the best underpinning for a needed new language of risk. The question is whether numbers that are less than hard, and perhaps even misleading when expressed as a single value, will do more harm than good. On the positive side, they might at least add some information about potency to the label carcinogen when discussing risk in news accounts.

Looking ahead Upton says, "The real risk with releasing this table is that it will set a precedent. People will take the numbers as meaning more than they really do. And there will be the temptation to extend the rationale to chemicals, where the uncertainties of transpecies and transdose extrapolations are so vast. I see an enormous nest of problems coming on the quantification issue. But I remain dedicated to the cause because without quantification the cause is lost."

Don Ritter

"The fray has entered the highest levels of American politics, and there is indeed a left-right breakdown on these issues. If the values of science are off on the sidelines watching, and only the values of the activists are entered into the debate, we're not going to get a balanced decision."

Karim Ahmed

"Environmentalists do not have a single voice. There are many different points of view, and we are not trying to do industry in. Environmentalists are not crazies. We are more than willing to make trade-offs."

Computer-based models are essential to designers and operators of such complex systems as electric generating plants. With computer models, the dynamic effects of changes in one or more variables can be analyzed without the laborious recalculation of the full set of variables. One problem with this approach, however, is that to realistically simulate complex interactions, the models themselves must be complex. This often leads to highly specialized computer codes that require substantial engineering and programming time to prepare and computer data processing time to run.

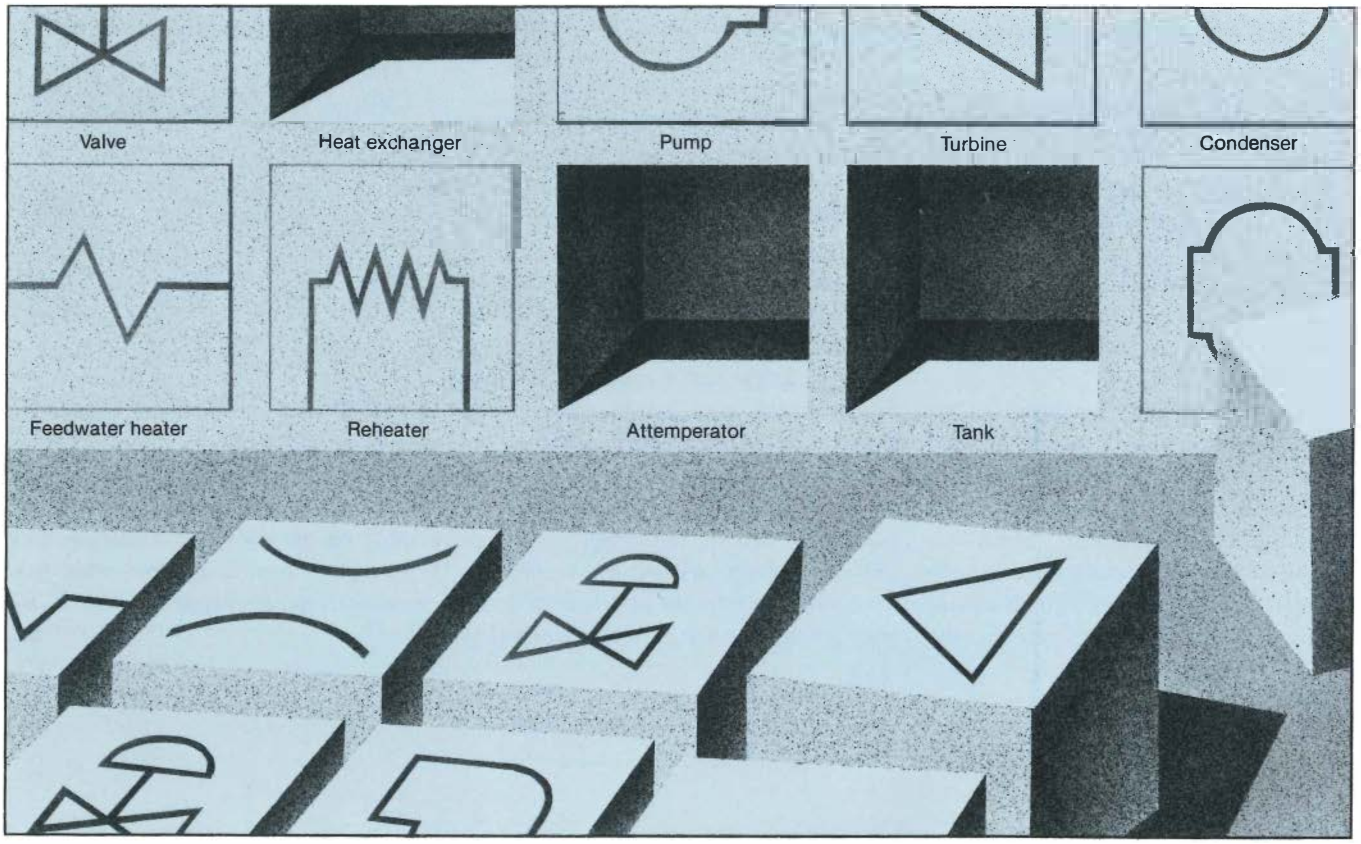
Because of the inherent complexity of modern electric power plants, few methods have been developed that are capable of simulating the dynamic and static behavior of entire plants, including balance-of-plant and control systems. The utility industry has relied on steady-state analyses, piecemeal simulation of components and subsystems, and cumbersome manual calculations. But today the availability of powerful, low-cost computers allows even a small utility to perform calculations in-house with the right software. This capability opens the door for utilities to pursue a better understanding of the dynamic behavior of their power plants—specifically, to optimize central operating systems and analyze the causes and effects of actual and potential transients.

In response to this need, EPRI's Nuclear Power and Coal Combustion Systems divisions developed the modular modeling system (MMS), an easy-to-use, flexible, economical, and accurate systems analysis code that can simulate the dynamic performance of nuclear and fossil-fuel-fired steam-electric power plants, their subsystems, controls, and components. The more than 30 utility and service organizations that have begun using MMS since its initial release in

RESEARCH APPLICATION

A Modular Code for Plant Dynamics

Modular modeling by EPRI's MMS computer code can simulate the dynamic behavior of both fossil-fuel-fired and nuclear power systems, from the smallest component subsystem to the entire plant.



the spring of 1983 are evidence that MMS fills an important niche among plant systems analytic tools.

Already available to EPRI members through the Electric Power Software Center, the MMS code has also been licensed to Babcock & Wilcox Co. The original code development was initiated with the Bechtel Group, Inc., and B&W under EPRI contract. S. Levy, Inc.; Boeing Computer Services, Inc.; Systems Control, Inc.; Jaycor, Inc.; and Science Applications International, Inc., also contributed to the code development effort, each in its area of expertise.

B&W will soon begin offering an improved version of MMS, together with a substantial support package, to utilities, architect-engineering firms, and other organizations with an interest in power plant design and operations analysis. Anticipated revenues from this arrangement promise to make MMS a self-supporting, commercial success. Commercial enhancements to the code are available to EPRI member utilities at a substantial discount.

A key feature of MMS is its modularity, which permits a user to build a system model from over 60 independently developed, preprogrammed models of fossil fuel and nuclear plant components, including balance-of-plant elements and control systems. MMS can represent in simplified form any component that can be described by a set of ordinary differential or algebraic equations, from a fossil fuel boiler or turbine generator to a breached reactor coolant system experiencing two-phase flow. The code automatically interconnects selected modules to model the actual power plant. This feature enables dynamic performance modeling that is sufficiently quick and inexpensive to include in the processes of plant design and troubleshooting.

An additional benefit is a reduction in the level of skill required of users. Engineers whose primary experience is in fields other than modeling can use MMS effectively without proficiency in the specialized programming of the component models themselves. This simplicity is designed to greatly reduce the cost of modeling, most of which lies in the engineering time and not in the computer services.

Integration of the modules is accomplished with one of two widely used simulation languages: the advanced continuous simulation language (ACSL), developed by Mitchell & Gauthier Associates, and EASY5, developed by Boeing. The simulation language translates user input from worksheets into a compiled FORTRAN program. It also provides a function for changing component parameters during a run and useful convenience features, including linear and stability margin analysis and input/output routines, such as line or print plotting. An additional capability under development will permit color graphic displays of MMS calculations, which have potential application for on-line plant performance analysis.

Intended for use during both plant design and operation, the code permits simulation of a wide range of transients (e.g., a heater drain pump trip, steam generator tube rupture, load rejection, or feedwater transient) that may be encountered with a proposed plant configuration. The possible causes and consequences of an actual transient can be investigated. In the case of fossil fuel plant applications, MMS provides dynamic modeling of cycling operation for transient analysis.

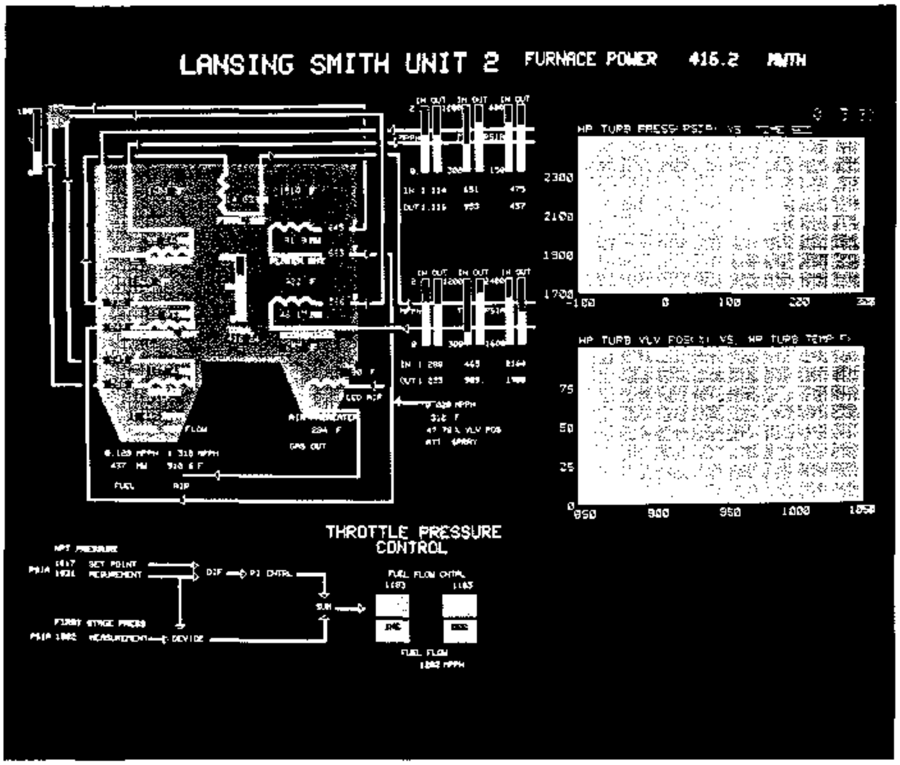
In nuclear plant operation, MMS is being evaluated for operator training, simulator model verifications, and procedures evaluation during postulated transients. In addition, the code permits testing of alternative control system configurations for optimal design; control gain settings can be determined during preoperational plant checkout. The strength of the code lies in its ability to handle scoping analysis of plant control systems.

Unlike other reactor transient analysis codes, such as RETRAN and RELAP, MMS is not designed for the detailed simulation of transients required in safety analysis for nuclear plant licensing. Rather, MMS is intended for transient scoping purposes—to provide a best-estimate solution for integration of primary processes, control systems, and balance-of-plant modules. MMS can run on utility-owned minicomputers as well as on the mainframe computers required for larger codes.

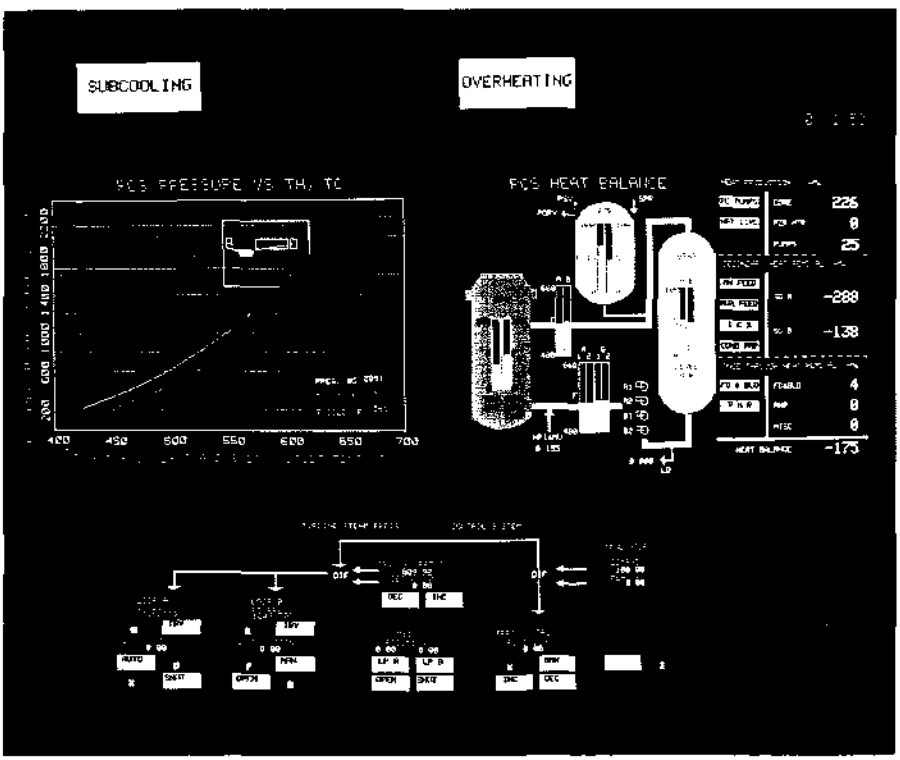
The accuracy of MMS for transient simulation has been validated against recorded transients in both fossil fuel and nuclear plants. Plant data, such as data from the Three Mile Island Unit 2 accident, were already available to validate nuclear modules, but the paucity of recorded transients on fossil fuel plants required an actual test. As the first major user of MMS, Boston Edison Co. volunteered its Mystic Unit 7, a 565-MW oil-fired plant, for the project. As a result of the test program of 22 controlled system perturbations and control system transients, Boston Edison recognized immediate benefits in improved plant performance even before MMS was fully verified and released.

The major incidental gain was in the analysis of stack gas and combustion air flow for a fuel saving of about 1%; a second area of saving involved securing one of two on-line steam air injectors. The total saving to the company from these control improvements was estimated at more than $1.3 million in the first year. "This research clearly shows the importance of our instrument and control systems on plant economics," according to Boston Edison's Edwin Haddad.

Ten EPRI member utilities participated in prerelease testing of the initial version of MMS over a period of 14 months before it was released for general use under EPRI license in April 1983. A second user group worked on code validation from April 1983 to September 1984 to test new modules in the MMS library. One utility used results of a transient simulation to correct an unsatisfactory heater drain pump and drain tank control in a nuclear



MMS can model any fossil fuel or nuclear plant configuration from its library of interconnectable modules. Graphic displays generated by the model can represent dynamic interactions of plant components in real time, indicating changes in key parameters as they would actually occur.



plant; three others used the code for guidance in the procurement of plant control systems—one for a new plant design, one for a major retrofit, and yet another to predict test results for a new plant startup.

In contrast to other utilities in the prerelease group who used MMS for whole-plant modeling, Duke Power Co. targeted its use on specific problem areas, using MMS to model control systems for its new Catawba nuclear plant and for a number of applications at its McGuire nuclear station. When a control system trip forced a 12-hour outage at McGuire, Duke engineers simulated operation with MMS; results led to new parameter settings that engineers feel confident will prevent future trips. "MMS can handle most anything in power plants, but we were the first ones who saw it as a really useful and practical tool in modeling control systems," says Alvin Sudduth of Duke's advanced engineering group. EPRI is now working with Duke to quantitatively document economic benefits to the utility from its use of the model.

As more utilities apply MMS to various plant design and operating questions, insights from these user experiences will be incorporated in future code enhancements. With extensive documentation and a well-organized user group in place, MMS promises to become an effective and economical addition to the analytic tools for power plant design, operation, and safety scoping evaluation.

Further reading

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This article was written by Taylor Moore. Technical background information was provided by Murthy Divakaruni, Nuclear Power Division, and Frank Wong, Coal Combustion Systems Division.

Nuclear Waste Office Pushes Toward 1998 Goal

DOE is committed to meeting its congressional mandate to begin accepting spent fuel for permanent disposal in a geologic repository by 1998.

Nuclear power supporters and critics alike applauded the passage of the Nuclear Waste Policy Act of 1982 (NWPA), which set the nation on a definite and direct course of action designed to effect a permanent solution to the problem of nuclear waste disposal from civilian power plants. The act established a policy, set up a schedule, mandated specific procedures, and targeted 1998 as the year by which the nation's first repository would be ready to begin accepting waste for safe and permanent disposal. Now, two years later, the United States can look back on a series of accomplishments in the federal program established to fulfill the mandates of the act, as well as forward to a number of major milestones that will bring the country closer to meeting the 1998 goal.

Among the accomplishments are the organization and staffing of the Office of Civilian Radioactive Waste Management within the Department of Energy (DOE) to manage the waste program and the nomination by the president and confirmation by the U.S Senate of Benard C. Rusche as head of the office; the formalization of contracts between DOE and all the nation's nuclear utilities that obligate DOE to dispose of the waste and ensure that the utilities will pay the full costs of that disposal; the establishment of the nuclear waste fund, through which the utilities pay for the disposal services; issuance of a draft mission plan describing the objectives, strategies, and projects of the program; and preparation and final issuance of the technical guidelines on which will be based the decision of where and in what medium the final repository will be sited.

In terms of milestones ahead, perhaps the most significant one for the entire program is scheduled to take place in the summer of 1985 when the secretary of energy formally nominates at least five sites considered suitable for further detailed investigation and recommends three to the president for the process of site characterization. "This first threshold is clearly the crucial one for the program," commented Rusche during an interview this summer. The decision will narrow the field of sites under consideration for the final repository to three, and those three sites will then undergo the characterization process, which involves detailed data collection and construction of exploratory shafts at each site. This is an expensive proposition—one calculated to cost a half billion dollars for each site—and will be a clear signal that the waste disposal program is truly on its way and is moving past the many technical and institutional obstacles it has faced in the past.

The issue of nuclear waste disposal from civilian power plants has been of concern since 1957, when the nation's first nuclear plant began operation in Shippingport, Pennsylvania. Since then nuclear utilities have accumulated over 10,000 tons of spent fuel, an amount capable of filling a football field 3 ft (0.9 m) deep. By the year 2000 the total spent fuel inventory is estimated to increase to 50,000 tons. Spent fuel contains highly radioactive waste products and must be isolated for human safety and protection

Rusche

for many years. Currently, utilities store spent fuel in the form of fuel rods in deep pools of water at their nuclear power plants. The water cools the rods and serves as a shield to protect workers from radiation. This was always intended as a temporary solution, however, because the practice requires constant maintenance and because there simply is not enough space at nuclear utilities to accommodate the anticipated need for storage.

The utility industry has been deeply concerned about the issue, particularly because several utilities may already be running out of storage space. The waste disposal issue has been a major stumbling block to public acceptance of the nuclear option, as evidenced most clearly in the late 1970s, when several states passed laws prohibiting the construction of any new nuclear plants until the waste disposal question was solved. It has always been the responsibility of the federal government to provide for the long-term disposal of high-level radioactive waste and spent fuel from civilian power plants. However, because of the controversial nature of the issue and the complex technical and institutional questions involved, resolution of the problem has taken many years.

During this time the federal government conducted an active research, development, and demonstration program designed to resolve many of the complex questions inherent in the safe disposal of nuclear waste. As a result, in April 1981 DOE issued a record decision that formally selected mined geologic repositories as the preferred means for disposal of nuclear waste. Then, in October 1981 President Reagan issued a nuclear policy statement that set as a key goal the public demonstration that the problems of nuclear waste could be solved. The impetus of these two developments helped to forge a bipartisan effort that led to the passage by Congress on December 20, 1982, of the first comprehensive waste management act in U.S. history. The president signed the legislation into law on January 7, 1983.

Site Approval

NWPA requires DOE to provide for the safe, long-term disposal of spent fuel and high-level radioactive waste in a geologic repository. Although much of the nuclear community would argue that spent fuel is not truly waste material because of the valuable energy content left in it in the form of unused uranium and plutonium, the term *waste* is used generically in the parlance of the act and the program to refer to both spent fuel and other forms of high-level waste from civilian reactors.

At the time that NWPA was passed, DOE already had an extensive R&D program under way, investigating various sites and geologic media as possible repositories for nuclear waste. Nine particular sites were being studied, and in February 1983, as required by NWPA, DOE formally identified those nine sites as potentially acceptable for the first repository. The sites are in six states: one in Nevada in tuff, a compacted volcanic ash; one in Washington State in basalt, a very-fine-grained rock formed by the solidification of lava; two each in Texas and Utah in bedded salt; one in Louisiana and two in Mississippi in domal salt.

During the past two years, DOE has held public hearings near the sites in these six states to solicit comments from interested parties and to aid in the preparation of environmental assessments on the sites. A draft assessment for each site will be published December 20, and a final assessment will accompany the nomination of sites for characterization.

Based on the environmental assessments, DOE will nominate five of the nine sites as suitable for site characterization and recommend three to the president to undergo the characterization process.

"Our recommendation will depend on which of the sites we think are most attractive," notes Rusche. "The act provides a couple of generic criteria, and the guidelines provide hundreds of criteria of a very specific nature." The act, for example, provides that the three sites should be in different media—not all salt sites or all basalt sites—and that there should be geographic diversity to the extent possible. The guidelines establish the performance requirements of the repository, define the technical and environmental qualifications that the candidate sites must meet, and specify how DOE will carry out the site selection process.

The president has 60 days to review and approve DOE's recommendation of the three sites for characterization. If the sites are approved, DOE must then submit a characterization plan for each of the three sites and hold a set of public hearings in the vicinity of each site to inform the public of the work to be done and to seek comments. Then DOE will proceed with site characterization, a job estimated to take at least five years.

Following characterization, DOE will complete a final environmental impact statement and recommend one of the three sites to the president as the best suited for the nation's first nuclear waste repository. Although the act prescribed that this recommendation should occur in 1987, DOE feels that more time is needed to obtain sufficient data through site characterization. The final recommendation is therefore scheduled to take place in 1990.

Based on the DOE recommendation, the president will then submit his final decision to Congress, along with the environmental impact statement. At this time, as permitted by NWPA, the affected state or Indian tribe may exercise what is, in effect, a veto right by presenting within 60 days a notice of disapproval to Congress. If this occurs, it would take both houses of Congress to override the veto. If Congress fails to override the veto, the selection is nullified and the president is given 12 months to submit another recommendation.

If Congress succeeds in overriding the veto or if no notice of disapproval is presented, the site designation is firm and within 90 days DOE will proceed to apply for a construction authorization permit from the Nuclear Regulatory Commission. NRC has three years to approve the construction authorization, and if it does, construction could begin by 1993. Although complete construction of the repository would take about eight years, DOE is proposing phased construction so that certain parts of the facility would be ready to begin accepting waste in five years—meeting the 1998 deadline.

Planning for Contingencies

Because NWPA anticipates that one repository may not be sufficient to meet the nation's total nuclear waste disposal needs, it requires DOE to carry out the siting and development activities for a second repository. DOE is doing this in its crystalline rock program, called thus because all the rocks being studied as media for disposal are crystalline rocks. As part of this effort DOE has been conducting literature studies of rock sites in 17 states: Connecticut, Georgia, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Virginia, Vermont, and Wisconsin.

These studies should be completed by the end of 1984 and DOE will identify potentially acceptable sites for the second repository during the summer of 1985. If, in fact, the need for a second repository is established, DOE will have to seek congressional approval. The second repository would follow the first in about five years, and until a second repository is in operation, the first is limited by NWPA to accepting 70,000 tons of spent fuel.

"We're proceeding as if there will be a need for a second respository," states Rusche. It also appears likely that the repository or repositories will be used for disposal of the solidified high-level waste that has accumulated from the nation's defense program. This waste is expected to reach some 10,000 tons in volume by the year 2020, and NWPA requires the president to decide by January 1985 whether this waste should also be placed in the repository developed for commercial spent fuel. This summer DOE issued a draft analysis of a study that concluded both waste categories should be disposed of in the same repository or repositories.

Along with plans for the final repository, DOE is also developing a proposal for what is called a monitored retrievable storage (MRS) option that could be used in the event that the first repository is not ready by the 1998 deadline. MRS would be an aboveground option for temporary storage of spent fuel in a different location from the permanent repository. MRS would permit continuous monitoring, ready retrieval, and periodic maintenance to ensure the containment of radioactive materials. NWPA requires DOE to develop and proceed with the MRS option through the design, siting, financing, and licensing stages. Eventual construction would require additional congressional authorization.

In June 1983 DOE submitted a report to Congress describing the R&D activities necessary to develop a proposal for construction of an MRS facility. DOE's detailed proposal for construction of an MRS is due by June 1985, and it is to include at least five designs for such a facility, based on alternative site/concept combinations for at least three sites. The sealed storage cask and open-field drywell concepts are being developed. The sealed cask concept has been selected by DOE as the preferred concept to be developed in detail.

Although the MRS option (if needed) would only be a temporary storage facility, Rusche and his people are beginning to look at ways it might eventually become part of what he calls an integrated radioactive waste disposal system. Such a system would include all the elements necessary for complete waste disposal—handling, consolidation, transportation, interim storage, and so on—integrated in such a way as to maximize safety and cost-efficiency and to minimize the number of miles the wastes must be transported and the number of states affected. As part of this system, as Rusche describes it, there conceivably might be an intermediate facility where waste shipments could be received and consolidated and then sent on to the final repository. Such a facility would have many of the features of an MRS.

"What I am talking about has two doors," explains Rusche. "It has a front door where you bring things in and work with them and a back door where you send them out. Clearly, it is not a substitute for a repository. Clearly, it is associated with a system that makes a repository functional and practical. We've just begun studies to develop this."

Meeting the Challenges

Rusche and his program managers face innumerable challenges in implementing the provisions of the NWPA and in meeting the 1998 goal. There are, of course, technical challenges, and Rusche stresses that the program is committed to attaining the highest possible level of technical excellence. He is, however, confident that the technology for waste disposal is sound and believes that the most important technical considerations now are those related to the specific geology and circumstances of the location, which will determine exactly how the repository has to be designed. "In that sense, it's elegant engineering instead of science," he explains. "We know enough to do everything we are talking about. We just have to find the right place to do it."

The more formidable of the challenges is the institutional/political challenge, which is "related to carrying out the process that will allow us to do the technical job." This challenge involves working with the other entities that have an interest in the repository and can affect its eventual success: the states and Indian tribes, other federal agencies, the utility industry, and the public. The dimensions of the challenge are clearly apparent.

For example, Rusche readily admits that he is facing hesitant if not absolutely negative attitudes on the part of the affected states and Indian tribes regarding possible siting of the repository within their boundaries. He has communicated with all the governors of the first six candidate states, and each governor has indicated unequivocal opposition to having the repository sited within his state. "Every one of them recognizes that Congress has spoken and the repository has to be somewhere," Rusche relates, "but each one wants to help us make sure that it is somewhere else."

Rusche's strategy for overcoming this resistance is to insist on technical excellence, to demand thoroughness and openness in his program activities, and to be willing to go an extra step, if needed, beyond the act's requirements to make sure that all necessary parties are brought into the review and comment process. He wants everyone to know that safety is his first priority, and although he is committed to meeting the 1998 deadline, he will not allow the standards of the program to be compromised in doing so.

"As I noted in my confirmation hearing, the schedule is important, and I'm committed to trying to meet it," he states. "But I'm much more committed to the end point than I am to each of the pieces in between. And there's no way we're going to get to the end point without having done the job responsibly and credibly. So if I ever get pushed to the corner—if to make a date required by the act would force us to publish a document that was inept or incomplete—I would opt for slipping the schedule or for changing the schedule."

This happened with the repository siting guidelines, which were due within 180 days of passage of the act but took, according to Rusche, a year and 180 days because of the special interactive, institutional processes involved. In preparing the guidelines DOE held five public hearings around the country, received more than 3000 comments from states and the public, held 29 individual or collective meetings with the states, and consulted extensively with other federal agencies. In the case of the environmental assessments, DOE elected to go an extra step beyond that required by the act and circulated the documents in draft form, delaying publication of the final environmental assessments until mid 1985.

"We concluded that it was not proper from an institutional standpoint, nor were we likely to have all the available input, technical or institutional, if we didn't have a chance for the states to comment on the draft," explains Rusche. "That's an example of the extent to which we have had to work out this relationship. It's one of the elements of the institutional picture, and it involves time."

However, Rusche does not feel that the program's efforts to provide extensive opportunities for review and comment are being used by states and other groups to inhibit the process. "I have not seen very much of what I would call people just trying to put sand in the gears," he commented. "I think the state and environmental groups recognize that the country has spoken and that it's to everybody's advantage to move on and get it done. And although groups in every one of the states have said they would rather the repository not be in their state, if it is going to be built there, they realize that their best interest is served by seeing that it is done right. This presents a very different environment from what has existed in other areas of the nuclear business," he continues, "where those opposed to a particular action were willing to lie down in front of the trucks.

"For the first time in the nuclear business we have the forces operating in the direction of progress rather than inhibiting or impeding action," he states. "It's exciting that the question is not whether to do it, but how to get it done. So much of the other effort is still aimed at people wanting to argue about whether we need

THE REPOSITORY

What will the nuclear waste repository look like? It will resemble a large mining complex with a waste-handling facility at the surface and a mine constructed 2000–4000 ft (610–1220 m) below the surface. On the surface, an area of about 400 acres (162 ha)—about the size of a shopping center—will contain the buildings and other facilities that will be needed during the 30–40-year operating period expected before final closure. Such structures will include railroad unloading areas; administration, maintenance, and warehousing buildings; water and sewage treatment plants; a storage area for excavated rock; and the principal structure, the waste-handling building.

From the waste-handling building, separate shafts will lead below the ground for various purposes: one for personnel elevators, one for lowering the nuclear waste canisters, and others for ventilation. Underground tunnels will spread out into an area of approximately 2000 acres (810 ha).

When shipments of nuclear waste arrive by rail or by truck at the repository, the canisters of waste will be unloaded from shipping casks and transferred to a shielded cell at the waste-handling center. Inspectors will examine the canisters to ensure their integrity, and then the canisters will be lowered through the waste shaft to the level of emplacement. There, a shielded transport vehicle will take the canisters to their final destination, which will be a hole drilled into the tunnel floor.

The canister will be lowered into the hole; a cap or plug will be fitted into the hole; and the hole will be filled to the floor level with a plugging material that provides radiation shielding for workers.

Eventually, when the holes are filled, the tunnels will be backfilled, and the shafts will be plugged, backfilled, and sealed. However, provisions are being made to allow for retrieving the waste canisters for up to 50 years after the emplacement of the last canister. The retrievability period will be determined by the secretary of energy at the time of emplacement. Once the repository is closed, however, all reasonable means will be taken to alert future generations to the location of the repository by such means as surface symbols and permanent records in libraries and computerized information centers. □

nuclear power. There isn't much argument about whether we need to go to final repositories."

Accountability to Utilities

Also an intrinsic part of the institutional picture are the utilities who generate the spent fuel and who are paying the costs of the program to dispose of it. NWPA provided that the waste disposal program be financed by a fund made up of fees paid by nuclear utilities and other generators of nuclear waste.

Two types of fees make up the fund. The first is a fee of one mill (one-tenth of a cent) per kilowatthour that utilities pay quarterly for all nuclear electricity generated. Utilities were required to begin paying this fee as of April 7, 1983, and collections by DOE through August 1984 totaled over $402 million. The second fee required is for what is called in-core fuel—the spent fuel and high-level radioactive waste generated by utilities prior to April 7, 1983. An amount equivalent to a charge of one mill per kilowatthour must be paid by utilities for this in-core fuel, and utilities are given three payment options to choose from in doing so. Utilities must decide by June 1985 which payment option they prefer.

Some $2.3 billion is expected from this payment, plus interest if a deferred payment option is chosen. The fees for the nuclear waste fund are reviewed annually and can be adjusted if they prove insufficient to meet the full cost of the program. Total costs are estimated to be approximately $20 billion in constant 1982 dollars. On the basis of current nuclear power generation projections, DOE estimates that revenue flows will be about $300–$400 million a year. In FY84, the program's spending authority under the nuclear waste fund was $327 million, plus $26 million in R&D funds appropriated by the Department of the Treasury. It is the revenue aspect of the waste disposal program that differentiates it from most other federal programs that are strictly taxpayer-funded and the feature that produces, as Rusche explains, "a far more explicit sense of accountability on my part" to utilities than would otherwise be the case. "I have very special fiduciary responsibilities to ratepayers and the companies from which the revenue is coming," he explains. In his confirmation hearing before the Senate Environment and Public Works Committee, Rusche stated his intentions to manage the waste disposal program as a business, and this is what he has done.

Since his confirmation he has concentrated on building a staff with experience and on developing systems that will allow him to know what is happening to the revenue, when it is coming in, and where it is going. "I'm going to find out very quickly where we're spending the money and whether it's producing the result that we agreed it was going to produce," he insists. "And if it's not, then we're going to change it." Rusche has retained an outside accounting firm to add an extra audit level to the program beyond DOE's internal auditors and the annual and quarterly program audits provided to the Senate Committee on Energy and Natural Resources by the General Accounting Office. "This will probably be the most heavily audited activity in government," he says, laughing, "and the most open. We start out with everything being born public and then it goes public from there."

Rusche views himself as the primary program contact with the utilities. On the industry's part, he sees the recently established ACORD Committee (American Committee on Radwaste Disposal) as the industry's most sharply defined mechanism for interaction. The ACORD Committee is a high-level group composed of seven utility chief executive officers—five from the investor-owned sector, one from the public sector, and one from the Tennessee Valley Authority (TVA).

EPRI has a small program to provide technical input into the ACORD effort. By late summer the committee had had two meetings and Rusche had attended both. "I suspect that their meetings will be monthly, and I suspect that every month I will have an opportunity to sit down with them and review what we have been doing and where we are and to obtain any reaction, criticism, or complaint," he states. "And from time to time I will have the opportunity to ask them to react in a special way. I welcome this opportunity—it's an absolute necessity in my opinion."

DOE is also working with utilities in other ways in implementing its waste disposal program. For example, DOE has joined with EPRI and several individual utilities in cosponsoring R&D efforts to develop new, more-reliable, and cost-effective technologies for interim on-site storage of spent fuel. Utilities are particularly interested in such improvements because interim storage of spent fuel is clearly a utility responsibility and cost until the federal repository is ready.

In one R&D project, DOE, EPRI, and Virginia Electric and Power Co. are cofunding efforts to develop a method of dry storage that would use metallic casks. In another dry-storage project, DOE, EPRI, and Carolina Power & Light Co. are investigating technology that employs concrete silo casks. DOE also has a cooperative agreement with TVA to demonstrate licensed storage in two prototype storage casks. DOE is also investigating rod consolidation methods that would involve dismantling the fuel assembly and rearranging the spent fuel rods into a more compact array. One project is already under way with TVA to demonstrate this technology, and DOE is negotiating another such project with Northeast Utilities, a project that is also sponsored by EPRI, Baltimore Gas & Electric Co., and Combustion Engineering, Inc.

Public Awareness

The general public is an important part of the institutional picture, and Rusche insists that his program will include a major effort to increase public awareness of NWPA and the federal efforts to fulfill its mandate. "We're going to go as far as is practical, reasonable, and ethical under the circumstances to make sure that people have every opportunity to know what we are doing," he says. "Outside of headquarters we have major efforts carried out by each of the program offices and project offices. And when the sites are selected for characterization, we'll have three very sharply focused areas of activity and attention."

What does he believe will be the effect of the federal waste program on public acceptance of the nuclear option? Already, he believes, people are not as alarmed about the waste disposal problem as they once were because they believe something is going to be done about it. And eventually, federal action in this area will remove the issue entirely as a major contention affecting public opinion on nuclear power's future.

For the immediate future, however, 1985 promises to be a year of activity, excitement, and progress for the nuclear waste management program. With the designation of the three sites for characterization and major decisions expected on defense waste and MRS, the program will truly be launched on its way toward a solution to the waste problem by 1998. ■

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

End-Use Catalog Speeds Access to EPRI Research Results

For the first time the research results of three EPRI technical divisions have been collected, cataloged, and indexed in one publication to make finding information quick and easy.

A new EPRI publication, *End-Use Catalog: R&D Projects and Products*, was published recently in response to member requests for an easy-to-use summation of EPRI research products. It contains brief descriptions of more than 200 projects, outlining past and present product research in EPRI's Energy Analysis and Environment, Energy Management and Utilization, and Electrical Systems divisions.

In the past, utility representatives have reported difficulty in locating research products they could use, pointing out that the title of an EPRI project does not always convey how it can be used in different areas. The *End-Use Catalog* is designed to avoid this problem.

The catalog lists the projects that involve utility planning, forecasting, and demand-side planning functions, as well as residential, commercial, industrial, and transportation technologies. In addition, projects are indexed by both subject and project number. Each research entry contains the title of the project, a summary of the project's background and objectives, and a statement of the results if the project has been concluded. For continuing projects, the current research status is indicated.

Products of EPRI research currently available are also provided, along with the name and telephone number of a contact. Information ranges from technical reports and associated publications to computer software and hardware, as well as new equipment licensed by EPRI.

Copies of the *End-Use Catalog* are being shipped to technical information coordinators at all EPRI member utilities; these coordinators are asked to inform the Institute of the number of additional catalogs they need. The catalog will be updated periodically as ongoing projects progress and new ones are begun. ■

Starr Wins Risk Analysis Award

Chauncey Starr, EPRI's founding president, has been presented with the Distinguished Contribution Award by the Society for Risk Analysis. The society was created in 1980 to consider questions of risks to health, safety, and the environment, with the aim of promoting knowledge and understanding of risk analysis techniques and applications.

Starr is highly respected in the field

of risk analysis. His article in *Science*, "Social Benefit vs. Technological Risk" (Vol. 165, 19 September 1969), presented a conceptual framework for risk/benefit decisions that has had an enormous impact in this field of study. Since then he has written numerous articles on the theory of risk analysis and its application to technology risk management.

In this, the first year the award has been given, three scientists were honored, including Starr. The other two recipients are Howard Raiffa, professor of managerial economics at Harvard, and Roy E. Albert, vice chairman of the Institute of Environmental Medicine at New York University Medical Center. ■

Tests of New Thyristor Promise Improvements in Power Equipment

A new semiconductor switching device tested under EPRI sponsorship shows promise for increasing the performance of electronic power equipment at lower cost. Researchers found that the new device—an advanced thyristor—is capable of faster switching times and can be controlled by simpler circuits than those in conventional, solid-state devices.

"The tests verify the thyristor's potential to increase the efficiency while reducing the size, weight, and cost of a wide range of electronic equipment, such as large converters, inverters, and adjustable-speed drives," explains EPRI Project Manager Ralph J. Ferraro.

The thyristor was designed by the Semiconductor Research Institute in Sandai, Japan, under the personal management of J. Nishizawa, director of the institute. Nishizawa calls the new device the static induction thyristor, or SiThy. The principal advantage of the SiThy is its ability to be controlled by low-level electronic signals, thus eliminating auxiliary components required for conventional thyristor circuits.

"The fast turn-on and turn-off capability of the device may permit higher-frequency operation and better control with fewer and less complex circuits," says Ferraro. Of the sample SiThy devices tested, some were observed to have turn-on/turn-off times of 1.4 to 2.0 microseconds, while other samples ranged from 2.5 to 5.0 microseconds. According to Ferraro, the higher switching frequency could contribute to significant reductions in the weight of magnetic components, such as transformers, inductors, and reactors. "The result would be reduced equipment bulk and cost," Ferraro said.

The low internal losses projected for the SiThy should result in more-efficient use of electrical energy in a wide variety of applications, according to Nishizawa. These include applications in the electric utility industry, such as inverters for fuel cell or battery storage systems and converters for photovoltaic or wind power generation systems. Applications are also expected for general industrial processes, such as ac and dc motor drives, electric heating, and power supplies, as well as for transportation machinery, such as electric locomotives, elevators, and escalators. ■

CALENDAR

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

JANUARY

16–17
Regional Conference: Compressed-Air Energy Storage
New Orleans, Louisiana
Contact: Robert Schainker (415) 855-2549

FEBRUARY

4–6
Seminar: Nuclear Safety Control Technology
Palo Alto, California
Contact: Murthy Divakaruni (415) 855-2409 or K. H. Sun (415) 855-2119

26–27
Continuous Emissions Monitoring, Guidelines Manual
Atlanta, Georgia
Contact: Charles Dene (415) 855-2425

MARCH

13–14
Regional Conference: Compressed-Air Energy Storage
San Francisco, California
Contact: Robert Schainker (415) 855-2549

20–21
Continuous Emissions Monitoring, Guidelines Manual
Denver, Colorado
Contact: Charles Dene (415) 855-2425

APRIL

9–11
Seminar: Power Plant Digital Control by Using Fault-Tolerant Computers
Phoenix, Arizona
Contact: Murthy Divakaruni (415) 855-2409 or K. H. Sun (415) 855-2119

30–May 2
Hydro O&M Workshop and Seminar: Dam Safety
Boston, Massachusetts
Contact: James Birk (415) 855-2562

MAY

6–9
1985 Joint Symposium on Stationary Combustion NO_x Control
Boston, Massachusetts
Contact: Michael McElroy (415) 855-2471

14–15
Regional Conference: Compressed-Air Energy Storage
Chicago, Illinois
Contact: Robert Schainker (415) 855-2549

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

GAS TURBINE COMBINED-CYCLE OPERATING PLANT PERFORMANCE SOFTWARE (EMAP)

An individual 80-MW gas turbine at full load will burn natural gas fuel at a cost of some $5000/h. Monitoring turbine efficiency and correcting degraded performance can save significant amounts of money. Because about two-thirds of the gas turbine power developed drives the compressor, any degradation in compressor performance can greatly change the net turbine power output. For this reason, utility gas turbines run at their designed efficiency and output only when they are first started and very rarely, if ever, after that. Accurately calculating the efficiency of different parts of the gas turbine and combined-cycle plant can pinpoint the maintenance/correction necessary to restore original efficiency and output.

EPRI began a project in early 1983 to produce software compatible with personal computers located in power plants. The software would monitor gas turbine combined-cycle performance and output by using data obtained from plant instruments without the addition of significant new or highly sophisticated equipment.

Software

The program, called the efficiency, maintenance, analysis program (EMAP), works backward from plant efficiency calculations and MW output measurements to indicate specific component degradation. It determines differences between expected and measured performance. Expected performance is derived from the manufacturer's specifications, and software to calculate this performance is included as a subroutine called NEWCLEAN.

NEWCLEAN should have to be run only once for a particular turbine site or possibly after a major overhaul when determining a new performance basis from which to derive future measurements. The NEWCLEAN program calculates all reference quantities, such as a first-stage nozzle flow parameter, that are later used to calculate deviations.

The NEWCLEAN program uses a subroutine called CMAP that measures the basic Brayton cycle and Rankine cycle thermodynamics. When calculated plant parameters are established for the new and clean conditions, these data are input to the basic EMAP. Additional data from station instrumentation describing a given day's operation are then input manually to EMAP. In addition to displaying differences in original plant performance and current performance, EMAP can also analyze errors in the measured data.

Once differences have been established between original and current plant conditions, a program called DMAP evaluates the data separately and outputs the effect of component performance changes on overall plant heat rate and output. In other words, the program first establishes the differences resulting from plant degradation over the years and then calculates the overall effect each component has on total plant performance. This enables the plant operator to compare the expected benefit of repairs with whatever the proposed cost might be. Once this process is complete, plant operators can evaluate how certain maintenance procedures can improve efficiency and output recovery.

Figure 1 shows the overall structure of the

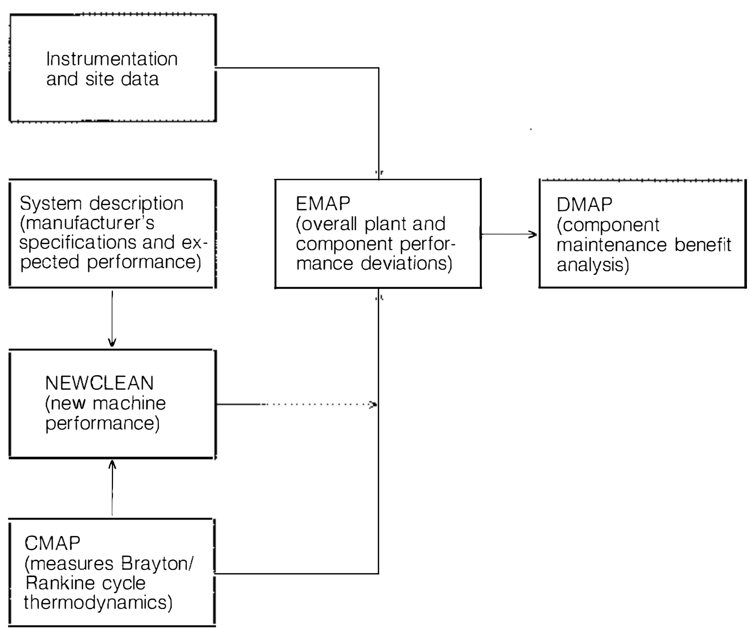


Figure 1 EMAP software. The program compares measured performance with expected performance so that operators can determine plant or component degradation and correct it.

Table 1
EMAP SOFTWARE DIAGNOSTICS

Gas Turbine	Boiler and Steam Turbine
Power	Steam output
Heat rate	Boiler losses
Fuel flow	Steam turbine power
Air flow	Steam turbine efficiency
Pressure ratio	Stack temperature
Exhaust temperature	Superheater fouling
Compressor efficiency	Evaporator fouling
Turbine efficiency	Economizer fouling
First-stage nozzle flow area	Condenser fouling
Firing temperature	Pressure drops
Control settings	Control settings

Table 2
INSTRUMENTATION REQUIRED FOR EMAP MEASUREMENTS

Gas Turbine Area	Boiler and Steam Turbine Area
Barometric pressure	Temperature of inlet gas
Wet bulb temperature	Temperature of outlet gas
Inlet air temperature	Boiler outlet steam temperature and pressure
Inlet pressure drop	Superheater outlet temperature and pressure
Liquid fuel flow	Evaporator drum temperature and pressure
Gaseous fuel flow	Economizer outlet temperature
Compressor discharge temperature and pressure	Feedwater temperature
Free turbine inlet temperature and pressure*	Return water temperature
Exhaust temperature	Boiler water flow rate
Exhaust pressure drop	Feedwater pump discharge pressure
Power (all generator outputs)	Bypass steam flow
Injected water flow and temperature*	Steam turbine inlet temperature and pressure
Injected steam flow, temperature, and pressure*	Extraction flow, temperature, and pressure
Compressor rpm*	Condenser pressure
	Forced circulation pump power
	Cooling-water inlet and outlet temperatures

*If applicable.

EMAP software package. Table 1 lists plant and component parameters that are displayed as output from the EMAP program.

Instrumentation

Project personnel surveyed several plants for testing EMAP. Of the plants surveyed, none had sufficient instrumentation to use the EMAP software immediately. Instrument modification in all plants will be necessary. Some plants will require slight modifications; others, perhaps major changes. Table 2 lists the instrumentation necessary to properly use all the EMAP functions.

Obtaining the proper instruments and determining their placement in the first program trial took a few months. The project final report will present the cost of procuring and installing these instruments as well as an estimate for bringing all the information into the control room.

All instruments are commercially obtainable. EPRI is currently working on calibration and other instrument maintenance necessary for the proper use of EMAP.

Field use

The first program run was completed in early July 1984 at the Salt River Project's Santan plant. Project personnel observed some software errors, which have since been corrected. Operators noted that inputting the data was cumbersome because many instruments are in remote locations. However, the program was relatively easy to use, and operators did not have to spend a great deal of time to become proficient. EPRI expects to complete at least two more field trials in different types of combined-cycle plants to determine software compatibility with different personal computers and instrument configurations.

The program shows that many areas of plant performance deteriorate. EMAP's virtue is in the consistency with which it displays changes in plant performance. As plant operators chart changes in plant performance over time, they will obtain a true picture that will assist them in establishing maintenance trade-offs. *Project Manager: Albert Dolbec*

BENCH-SCALE LIQUEFACTION OF WESTERN COALS

EPRI has sponsored bench-scale work on the liquefaction of western subbituminous coal. The Clean Liquid and Solid Fuels Program emphasizes development of two-stage liquefaction, a technology that could potentially reduce the cost of clean liquid fuels from coal by both increasing the yield of distillate produced from coal and reducing the amount of hydrogen required. Researchers have tested various process configurations to liquefy subbituminous coal. Two configurations—integrated two-stage liquefaction (ITSL) and doubly integrated two-stage liquefaction (DITSL)—have demonstrated superior performance in distillate yield and hydrogen consumption. Integrated systems link two reactors by recycling various process streams. The result is an interplay between the reactor systems. Varying the operating conditions of either or both reactors can produce a range of products from distillate to residual fuel oil in practically any combination.

Bench-scale facilities

Many recycle stream combinations can link the two reactor systems. Determining which streams and in what quantities to recycle was an objective of an EPRI project (RP1715-1). EPRI and Kerr-McGee Corp., who cofunded the project, built a bench-scale continuous coal liquefaction unit at a Kerr-McGee site near Oklahoma City. The unit can perform all the operations necessary to liquefy coal except manufacture hydrogen: coal liquefaction, critical solvent de-ashing and fractionation, catalytic hydrogenation, and distillation. The bench-scale unit can process ~15 lb/h of coal and can operate either one reactor or both reactors in completely integrated fashion. Operators can make accurate material balances around each section, as well as around the entire unit.

The bench-scale project focused on testing a number of two-stage process configurations prior to testing at EPRI's larger pilot plant test facility at Wilsonville, Alabama. This facility is operated by Southern Company Services and is cofunded by DOE.

Coal resources

Of the 1760 billion (10^9) short tons of currently identifiable total coal resources in the United States, subbituminous coal's 485 billion tons is a major asset, second only to bituminous coal's 747 billion tons. Lignite contributes 478 billion tons. In general, subbituminous coal is inexpensive to mine, but most of the reserves are in Alaska, Montana, and Wyoming—away from large population areas. EPRI's interest in this coal type is not based solely on the large reserves but also on the fact that the coal is peculiarly different from other coal types, such as lignite and bituminous.

The chemical and physical characteristics of subbituminous coal fall between those of lignite and bituminous coals, probably because subbituminous coal is not quite as old as bituminous coal and not quite as young as lignite. In contrast to bituminous coal, subbituminous coal is generally noncaking (it does not agglomerate when heated), has a high moisture content (30–40% of the as-mined coal), has high oxygen (20–30% of the moisture- and ash-free coal), has low heating value (fewer than 10,000 Btu/lb, dry-coal basis), has slagging ash characteristics (high content of alkali metals and low iron), has poor grindability, and is pyrophoric. All these factors—large reserves, resource inaccessibility, low Btu value, and poor transportability because of its high moisture content and pyrophoric nature—make subbituminous coal an excellent candidate for coal liquefaction.

Coal chemistry

Converting coal from a solid to a liquid requires increasing the coal's hydrogen content. Instead of relying primarily on high pressure to effect this increase (as was the practice in the 1930s and 1940s), modern technology uses a catalyst to facilitate the transfer of gaseous hydrogen to the coal.

Present-day coal liquefaction technology restricts practical operating pressure to approximately 3000 psi (21 MPa) or less. This restraint derives from today's design and construction practices for large vessels. Liquefying coal effectively at lower pressures demands a good understanding of coal chemistry.

EPRI has sponsored basic research in coal liquefaction chemistry, including studies on the molecular structure of subbituminous coal (RP2147-4, RP2383-3). Investigators found that subbituminous coal is not the condensed and highly aromatic structure once supposed. Rather, it consists of low-molecular-weight units joined by various alkyl (carbon-carbon) and ether (oxygen) linkages, as well as associative forces (hydrogen bonding). EPRI concluded that with proper chemistry, subbituminous coal liquefaction could yield more distillate. In practice, however, subbituminous coal is difficult to liquefy under conventional liquefaction conditions. EPRI set out to unravel the reasons (RP2147-5).

Researchers discovered that subbituminous coal was extremely reactive thermally (RP2147-5). Study suggests that under conventional liquefaction conditions a large portion of the small molecules in subbituminous coal thermally combine to form heavy-molecular-weight materials and gas rather than yielding appreciable amounts of liquid. This extremely high thermal reactivity is attributed to the large quantity and type of oxygen functional groups present in the coal (RP2147-5, RP2383-3).

A study on coal's molecular structure has shown that two-thirds of the oxygen in subbituminous coal is present as polyhydroxyl compounds, quinones, and/or hydroquinones. These oxygen structures are highly reactive thermally, which may explain the retrogressive nature of the reaction products of subbituminous coal. Interestingly, hydroquinones are excellent hydrogen donors and depolymerization catalysts. Thus coal used as an additive to hydrogenation systems can upgrade petroleum resids (RP2383-1). The coal itself converts best in the presence of resids of high nitrogen content.

Armed with the data indicating that the oxygen in the coal is largely responsible for the poor liquefaction performance of subbituminous coal, EPRI began research on chemistry that would eliminate or block reactions of the oxygen functional groups (RP2147-5, RP1715-1). Work with heterogeneous catalysts, such as iron oxide, and homogeneous catalysts, such as hydrogen sulfide and basic nitrogen solvents, has been successful in eliminating oxygen from coal.

Basic nitrogen solvents are extremely effective in liquefying subbituminous coal. Their practical use, however, has been hampered by irreversible losses of the solvents. Work under RP2147-5 showed that use of hydrogen sulfide could inhibit basic nitrogen solvent loss to the heavy liquefaction products (residuum) while still taking advantage of the solvent's basic character. The use of high-boiling basic nitrogen compounds, whether from coal or such sources as oil shale and petroleum resids, also promises to improve yields without incurring losses. Actually, some fraction of the residuum recycled in the two-stage liquefaction configuration consists of basic nitrogen compounds. Their presence in the two-stage recycle streams could contribute to the superior performance that has been observed in integrated two-stage processes.

EPRI also tested iron oxide and hydrogen sulfide as catalysts with subbituminous coal (RP1715-1). Iron oxide appears necessary to satisfactorily convert subbituminous coal to a soluble product. The addition of hydrogen sulfide in conjunction with iron oxide greatly enhanced the distillate yield. Although the active catalytic species is still not known, hydrogen sulfide by itself is an excellent catalyst for promoting hydrogen transfer (RP2147-5). Iron oxide, on the other hand, is an excellent deoxygenator and coal conversion catalyst. Work under RP1715-1 showed that the hydrogen sulfide catalyst was needed in the early stages of coal dissolution to impart the greatest catalytic effect.

Two-stage liquefaction

ITSL and DITSL are two-stage process configurations that differ in the type and quantity of process streams recycled between the reactors. ITSL and DITSL, as well as other process configurations, were tested on the bench-scale unit with subbituminous coal. ITSL and DITSL demonstrated the best performance, yielding the most distillate and consuming the least hydrogen.

Figure 2 shows the ITSL and DITSL process flow. Both configurations use the Kerr-McGee critical solvent de-ashing and fractionation process (CSD), which uses a proprietary solvent near or above the critical temperature of the solvent. When mixed with raw coal liquefaction products, the critical solvent allows the rapid separation of solids (ash and unconverted coal) from the raw liquefied coal. Solids separation in the CSD process is ~100–200 times faster than in conventional settling processes.

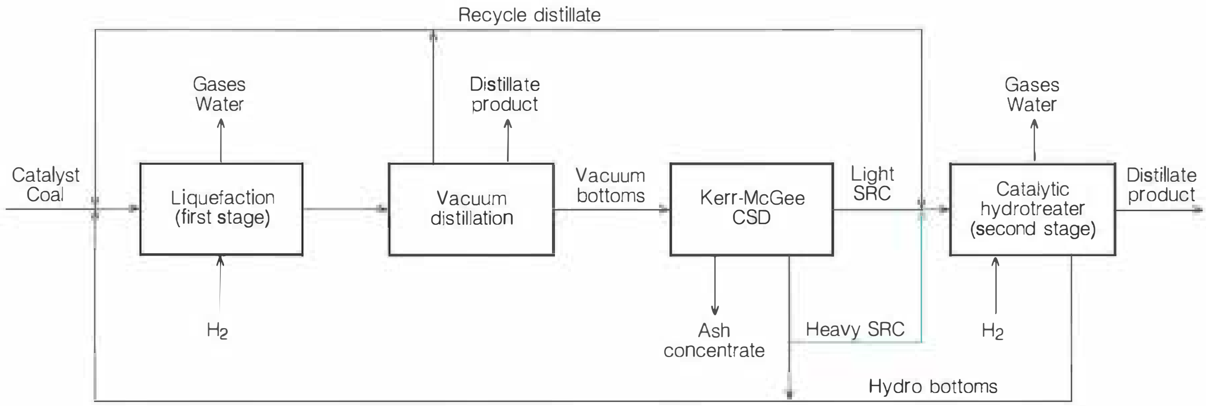
The CSD process can fractionate the de-ashed coal product into any number of parts in molecular weight order; each succeeding fraction is lower in molecular weight. The lighter the fraction, the lower the ash content—for example, light solvent-refined coal (SRC) usually contains less than 300 ppm ash.

In DITSL, the de-ashed coal product is fractionated into two parts, light SRC and heavy SRC, which is DITSL's advantage over ITSL. In ITSL no fractionation is carried out. Even though both configurations produce approximately the same distillate yield and consume about the same amount of hydrogen, DITSL feeds only light SRC diluted with thermal distillate solvent to the hydrotreater (second stage); ITSL feeds whole SRC (also diluted with thermal solvent). Its ability to feed only light SRC to the hydrotreater gives DITSL two major potential advantages over ITSL: (1) Less feed to the hydrotreater allows for a smaller hydrotreater (lower capital costs for the plant), and (2) the quality of the feed to the hydrotreater is considerably better (less ash and lower molecular weight, allowing for better catalyst life).

ITSL and DITSL bench-scale runs tested iron oxide and hydrogen sulfide as catalysts for the first stage. As the basic research showed, these catalysts were extremely effective in liquefying subbituminous coal. A commercial hydrotreating catalyst was used in the second-stage hydrotreater. In both ITSL and DITSL the second stage is operated at relatively low temperatures, less than 650°F (340°C).

Second-stage operating philosophy differs somewhat from past operation. The hydrotreater is currently operated to increase the recycle stream's hydrogen donor content and increase the recycle stream's susceptibility to cracking when recycled to the first stage. In the past the hydrotreater's purpose was to crack the heavy feed to distillate. This present mode of operation greatly increases the life of the second-stage catalyst.

Figure 2 A simplified process flow diagram for two options in two-stage liquefaction (ITSL and DITSL). The difference in the options is the type of hydro resid being recycled. In DITSL only light SRC is hydrotreated and recycled with unhydrotreated SRC, while in ITSL both light and heavy SRC (indicated by the color arrow) are hydrotreated and recycled.



DITSL and first-generation processes

Table 3 compares typical bench-scale and pilot plant DITSL yields with first-generation configuration yields.

The comparison clearly shows an increase of at least 13% in DITSL distillate yield over first-generation reactor yield. Hydrogen consumption is reduced by 28%. Comparison of DITSL yields with first-generation plant yields shows the improvement in distillate yield to be even greater (29% or more). A problem with first-generation plants is that even though reactor yields are relatively good, the total plant yield cannot be completely recovered because some of the liquid product is needed to carry the ash and unconverted coal from the unit and therefore cannot be recovered as product. In two-stage processes essentially all the distillate produced can be recovered.

DITSL consumes considerably less hydrogen in eliminating oxygen. Most of the oxygen is removed as CO/CO_2 gas rather than as water, which represents about 50% of the hydrogen savings. Most of the remaining hydrogen savings can be accounted for in the lesser yield of hydrocarbon gases. DITSL makes a slightly heavier distillate product, which saves more hydrogen.

In addition, DITSL offers other advantages that are not quite so obvious.

- Product slate flexibility
- Better operating reliability

Table 3
COMPARISON OF DITSL WITH FIRST-GENERATION PROCESS
(subbituminous coal)

Overall Yield (wt% moisture- and ash-free coal)	DITSL Bench-Scale	DITSL Wilsonville Pilot Plant	H-Coal First Generation Reactor	H-Coal First Generation Plant*
CO, CO_2, H_2S, NH_3	9.1	7.5	3.7	3.7
Water	10.7	11.9	20.3	20.3
C_1 to C_3 gases	13.9	8.2	11.7	11.7
C_4 to <850°F (454°C) distillate	50.3	54.5	48.4	42.4
>850°F distillate	—	1.5	—	—
Coal values rejected with ash	21.4	21.8	23.3	29.3
Hydrogen consumption	5.4	5.4	7.5	7.5

*Reactor yields adjusted to produce 50% solids in vacuum still bottoms.

- Better catalyst life
- Less catalyst consumption

The future

Two-stage liquefaction is clearly superior to first-generation processes. However, more work is needed to optimize the two-stage concept. EPRI will continue research to (1) develop better first-stage catalysts and optimize process conditions for reducing gas and yielding more distillate; (2) optimize the amount and quality of hydrogenated resid and distillate recycle to reduce gas and improve distillate yields and to reduce the size of the hydrotreater; (3) improve product quality to reduce sulfur and nitrogen content; and (4) improve process configuration to enhance mechanical and thermal efficiency. *Project Manager: Conrad Kulik*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

FGD MATERIALS

Corrosion and erosion are the leading causes of reduced flue gas desulfurization (FGD) system reliability. The problems are most acute in such equipment as outlet ducts and stack liners because these parts normally have no installed spares, and failure requires plant shutdown. To improve understanding of materials performance in FGD systems, EPRI initiated a comprehensive research program that has two major objectives: to identify corrosion and erosion problems in commercially available FGD processes, and to investigate the problems and recommend solutions on the basis of laboratory and field tests. This research will help utilities select the most cost-effective FGD system materials.

FGD process and materials suppliers tested FGD system materials before EPRI initiated this research. Although these earlier studies yielded valuable corrosion data, the environmental conditions in these studies were often not well characterized. Consequently, data interpretation was sometimes difficult, and a more systematic approach to materials testing seemed necessary. EPRI therefore initiated several projects to address these deficiencies.

In the first project, the contractor surveyed existing wet FGD systems and documented construction materials and their performance. This survey, completed by Battelle, Columbus Laboratories in 1980 and published in 1981 (CS-1736), was updated in 1984 (CS-3350). The survey showed that many kinds of construction materials have been used in FGD systems, including metals, organic linings, and ceramic and other inorganic linings. The most frequent problems occurred in the outlet ducts and stacks, both of which are critical areas because failures result in prolonged boiler outages with loss of generating capacity. Less-frequent and less-critical failures occurred in the prescrubbers, absorbers, reheaters, dampers, pumps, pipes, and valves. The survey also showed that no material was problem-free, and industry uncertainty about material behavior was exacerbated by reports that materials that had worked well in one scrubber had failed in others.

Early projects to simulate scrubber environments in the laboratory were only partially successful. Although researchers knew that system environment depends on system location, they considered only pH, temperature, and chloride content. EPRI report CS-2537 describes the performance of alloys and coated panels in these relatively simple simulated outlet duct environments; however, it now appears that the corrosion rates of alloys in chemically simple environments may differ significantly from corrosion rates in the relatively complex environments found in real scrubbers.

Quite apart from any effects of environmental composition, lining performance is not easily reproduced in the laboratory for other reasons. For example, temperature differences over wide areas of large scrubber components may cause stresses that cannot be duplicated easily in a laboratory on small sample panels. Therefore, laboratory test results cannot always be extrapolated to full-scale applications. Consequently, to evaluate FGD system linings, researchers decided to limit laboratory tests and rely more heavily on monitoring relatively large test patches in actual operating systems.

Field studies

EPRI selected South Mississippi Electric Power Association's R. D. Morrow generating station as a field test site for materials because it represents the state of the art in FGD design, and the outlet ductwork has had severe corrosion problems since the system began operating in 1978. The station has two identical units equipped with an FGD system from Environeering (a division of Riley Stoker Corp.). Figure 1 shows the system gas path.

Researchers placed alloy samples in two sections of Unit 2's mixing zone: opposite the bypass duct and opposite the absorber outlet. In Unit 1 they tested seven organic linings commonly used in FGD systems on a wall section 38 ft (11.6 m) high in the same locations opposite the bypass duct and absorber outlet. Each lining was applied in strips 2–3 ft (0.6–0.9 m) wide from the bottom to the top of the 38-ft test section. The project team also applied two inorganic linings in strips 4 ft (1.2 m) wide on adjacent walls.

The seven organic linings tested were a fluoroelastomer, a glass-flake–reinforced vinyl ester base with a fluoroelastomer top coat, a glass-flake–reinforced vinyl ester alone, an alumina-and-glass-powder–reinforced modified epoxy, an alumina-and-glass-powder–reinforced multifunctional epoxy, a glass-flake–reinforced modified epoxy, and a fiberglass-reinforced polyester.

The two inorganic linings were a Gunited silicate cement with a silica-filled membrane and a borosilicate–foamed-glass block with a polyurethane membrane.

Researchers visually inspected the linings during scheduled outages after 6, 12, and 18 months of testing. At the end of 18 months, two 1-ft^2 (0.3-m^2) panels of each lining, including the substrate, were cut from the lower duct wall opposite the absorber outlet and from the upper portion opposite the bypass duct for further analysis. The panels were examined with an optical microscope, a scanning electron microscope, an energy dispersive X ray, an X-ray diffractor, and an infrared spectroscope.

Figure 1 FGD system ductwork arrangement at the R. D. Morrow generating station. Alloy samples (Unit 2) and lining samples (Unit 1) were installed on the mixing zone wall opposite the bypass duct and the absorber outlet.

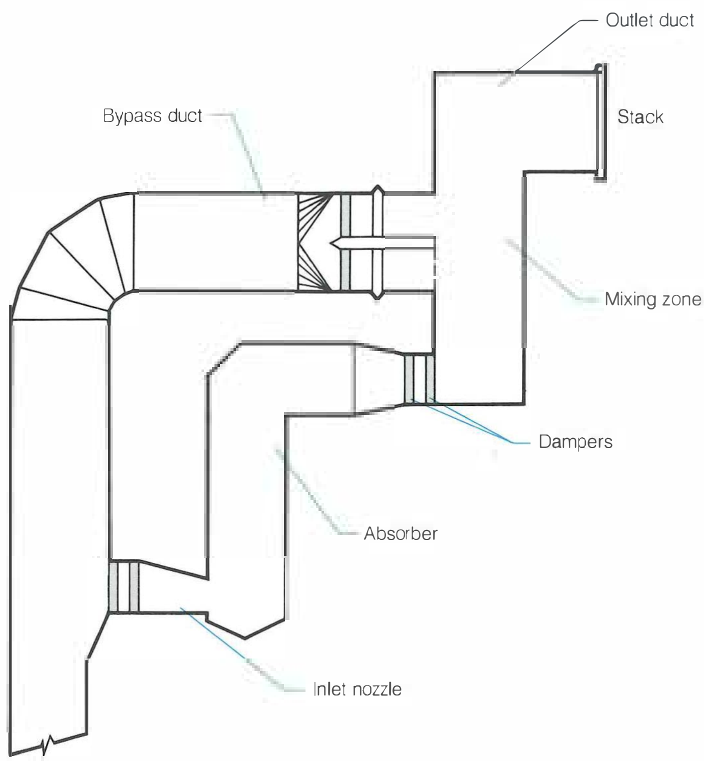


Table 1
AVERAGE CORROSION RATES
(μm/yr)[a]

Alloy	30 kg/m³ Chloride pH 1	30 kg/m³ Chloride pH 4	100 kg/m³ Chloride pH 1	100 kg/m³ Chloride pH 4
Hastelloy C-276	80	0	0.5	0.5
Inconel 625	343	0.02	18	0.8
317 LM stainless	2832	0.2	63	3.7
316L stainless	4077	1.1	97	4.8
Ferralium 255	389	1.1	50	1.0
Titanium 2	99,800[b]	0	1.3	0.1
TiCode 12	1274	0	1.4	1.1

[a]Average rate during a three-month exposure to simulated prescrubber environments at 93°C; Cl:F = 10:1.
[b]Specimen completely dissolved in one week.

After 18 months of exposure, few lining materials survived without failure. However, the borosilicate block did not show any deterioration, and the vinyl ester and epoxy linings showed only minor localized failure. The Gunited silicate cement, fluoroelastomer, and fiberglass-reinforced polyester suffered delamination. Although the linings usually failed by separating from the wall and cracking, in most cases they still provided some protection.

To help characterize the environment inside the duct and to better understand the corrosion chemistry, the project team installed condensate collectors in the Unit 2 outlet duct. Analysis showed that the condensate contains significant levels of dissolved sulfate (59,200 g/m^3), chloride (4800 g/m^3), fluoride (2590 g/m^3), aluminum (8060 g/m^3), iron (2630 g/m^3), magnesium (5460 g/m^3), and sodium (4920 g/m^3). These values are higher than previously anticipated and provide valuable input to future simulations of duct environments in the laboratory.

Burns & McDonnell Engineering Co. studied environmental characteristics in other FGD system areas (CS-3240). In this work the contractor used a controlled condensation method called selective acid deposition testing to obtain environmental data from the ducts.

These studies show that scrubber environments are chemically complex. Researchers speculate that some of the species, even though present in small amounts, could significantly alter the performance of the lining materials.

Laboratory studies

As a first step in identifying the effects of such species on material integrity, researchers investigated the effect of fluoride on alloy corrosion in the laboratory; Table 1 lists selected results. Most notable is the very high corrosion rate observed in the titanium alloy in the pH 1 solution containing 30 kg/m^3 (i.e., 30,000 ppm) of chloride. Some investigators quickly challenged the relevance of this result, and indeed, the concurrent field tests in the R. D. Morrow duct and other locations did not substantiate it. Thus, the solutions used in the laboratory did not appear to accurately simulate actual scrubber conditions, even with added fluoride.

After examining available chemical analyses of coals, bottom ashes, lime, limestone, and FGD process streams in detail, as well as reviewing ongoing studies at the R. D. Morrow station and other corrosion literature, researchers concluded that certain species were most likely to affect the corrosion rates of nickel-, iron-, and titanium-based alloys (Table

Table 2
CORROSIVE SPECIES

Species	Maximum Concentration (kg/m^3)
Mg^{++}	5
Ca^{++}	1
Al^{+++}	2
Si^{++++}	0.1
Cu^{++}	1
Cr^{+++}	0.5
Fe^{+++}	2
*Na^{+}	
NO_3^{-}	0.2
MoO_4^{--}	0.3 (0.2 Mo)
PO_4^{---}	1.5 (0.5 P)
Cl^{-}	100
F^{-}	10
Br^{-}	0.5
I^{-}	0.1
*$SO_4^{=}$	

*Na^{+} or $SO_4^{=}$ added as necessary for ion charge balance.

2). The values in the table represent the upper limits expected in FGD systems. Battelle and Rockwell International Corp. have developed a carefully planned statistical approach for identifying the synergistic as well as the principal effects of exposing alloys to solutions containing the Table 2 corrosive species (RP1871-6, -7). The projects should be completed in early 1985.

Other studies

Another EPRI-sponsored project will study the chemistry at the lining-substrate interface to help determine failure mechanisms in FGD linings, will investigate lining permeability, and will examine the effect of a variety of surface treatments before lining application. This effort is under way at Lehigh University (RP1871-5).

Ceramics, such as acid-resistant bricks for stack linings, Gunited cements in stack linings and ducts, and ceramic spray nozzles, have seen some use in FGD systems. EPRI is sponsoring a project at Ohio State University to determine the engineering properties of other selected ceramic materials and evaluate their potential for use in FGD systems (RP1871-11). In addition, Burns & McDonnell have begun to investigate the reasons for leaning in numerous acid-resistant brick stack liners (RP1871-13).

In another EPRI project (RP2248), a team of materials and process specialists investigated numerous rubber lining failures. They found that both the materials and their application were insufficient to ensure a successful corrosion-resistant lining. As a result of these findings, EPRI and Radian Corp. are preparing guidelines for specification, application, and storage of FGD system rubber linings.

Other EPRI research on FGD system materials are a study by La Que Center for Corrosion Technology on the potential use of corrosion inhibitors in FGD systems (RP1871-10); development of a corrosion monitor by the University of Manchester Institute of Science and Technology that would facilitate materials testing and could help optimize operating practices (RP1871-14); and development by Battelle of electrochemical potential control techniques for controlling corrosion (RP1871-15). As the projects have just begun, no results are currently available at this time.

These projects should uncover more cost-effective solutions to FGD system materials problems. Improved linings, electrochemical protection techniques, or even corrosion-inhibiting additives may improve FGD system performance and reliability. *Project Managers: Charles Dene and Barry Syrett*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Vice President

OVERHEAD TRANSMISSION

High-Voltage Transmission Research Facility

This facility, originally known as Project EHV, then Project UHV, is now known as the High-Voltage Transmission Research Facility, or HVTRF (RP2472). It is still staffed by experts in transmission line research and testing and still offers complete electrical testing capabilities as in the past, but two major changes have taken place. First, HVTRF now has full bipolar HVDC testing capabilities for any voltage up to ±1500 kV. Second, and probably more important, the research and testing capabilities of the facility are now directly available to the utility industry.

Located on 30 acres in Lenox, Massachusetts (near Pittsfield), HVTRF is well-situated to assess the effects of a wide range of weather conditions on high-voltage lines. Surrounding hills shelter the site from high winds and severe conductor vibration, but the facility experiences ample fog, rain, snow, and temperature variations for electrical and environmental studies. A large fog chamber can be used to exaggerate known weather conditions.

Work at HVTRF focuses on evaluating insulator performance, corona phenomena, electric and magnetic fields, and all aspects of transmission line design and performance. The following are typical test objectives.

- Define operating characteristics of HVAC or HVDC lines by testing full-scale prototype lines
- Assess the nonbiologic field effects of induced voltages and currents on conducting bodies
- Investigate ways to reduce radio noise and audible noise emanating from high-voltage lines
- Evaluate the electrical strength of insulators subjected to surface contamination
- Determine the effect of tower geometry on air gap insulation strength
- Determine the effects of switching-surge amplitudes on line insulation design
- Develop guidelines for hybrid ac/dc lines

Over the last two years, much of HVTRF's full-scale test line time has been devoted to testing configurations that represent lines to be built in the United States. This work has been sponsored by various utilities, and the results will be contained in the *HVDC Transmission Line Design Reference Book* to be published in 1986 (estimated).

An interim report, *HVDC Transmission Line Research,* was published in 1982 (EL-2419). In mid 1985, EPRI plans to publish a parametric study of HVDC insulator performance based on a large number of tests made on a wide variety of existing and experimental insulators in HVTRF's fog chamber. This parametric study is targeted to highlight those factors leading to improved flashover performance. One very obvious conclusion from the tests is the superior performance of composite insulators under light to medium contamination. EPRI and its advisers place development of a better HVDC insulator as a high-priority research need. *Project Manager: John Dunlap*

UNDERGROUND TRANSMISSION

Morphology of XLPE cable insulation

A project is in progress at the University of Utah to develop an understanding of the morphologic characteristics (form and structure) of cross-linked polyethylene (XLPE) in cable insulation (RP7891). The project objectives and approach have been described in earlier *Journal* articles (November 1981, p. 45; October 1983, p. 47).

This area is of interest because the morphology of XLPE may influence cable life, but until the project was initiated, XLPE had not been studied nearly as intensely as many other polymers. Also, much of the information reported in the literature (even at present) inadvertently focused on studying artifacts rather than the true morphology, and this project was designed to clarify that situation.

Over the past year this effort focused on examining XLPE insulation from extruded dielectric transmission cables. Cables that were cross-linked by different methods (the dry nitrogen cure, the conventional steam cure, and the experimental liquid cure approach from RP7829) were examined, and the sol-gel relationship across the entire cable wall was ascertained. Studies of crystalline melting behavior and thermal aging show that cables cured in different ways responded differently to thermal aging; this is demonstrated by varying extractable fractions and slightly different melting endotherms across the cable wall. Both of these parameters contribute separately to the thermal aging behavior. Also, the fine structures of the steam- and dry-cure cables are different.

The significance of potential separation of the sol and gel fractions (which would occur only under partial melting rather than full melting—for example, 90–110°C) continues to be investigated. Such an effect have impact on the behavior of cables subjected to thermal overload. This information will ultimately be of value in understanding both the influence of manufacturing methodology and aging conditions on cable operating reliability. This project will continue through the middle of 1985, at which time a detailed final report will be prepared. *Project Manager: Bruce Bernstein*

DISTRIBUTION

Lightning research

The optimization of lightning surge protective practices for distribution lines partially depends on a knowledge of the surges that have to be protected against. Little work to determine the characteristics of surges has been done, primarily because of the unavailability of the necessary instrumentation. Under contract to EPRI, Macrodyne, Inc., has developed an instrument that has the capability of recording lightning current and voltage surges on distribution lines (RP2005).

Figure 1 shows a block diagram of the recorder. Either a surge voltage sensor, suitable for installation on distribution lines, or a surge current sensor, suitable for installation on unenergized conductors, can be plugged into the recorder. The analog input signal is converted to digital quantities and stored in a solid-state memory. Current waves are also integrated by the charge integrator, and the total charge is determined and stored.

Communication with the unit is accomplished by using a portable computer (the playback-control unit) plugged into the optic fiber communication links. This unit is used not only to unload data from the recorder but also to check recorder functions and set such variables as trigger level, full scale, and time.

Data are processed in three ways by the playback-control unit. As the data are transferred to the unit, a visual display is provided, which is then printed on a paper tape. This enables the technician to observe the process and determine that everything is operating correctly. The data are transferred to a magnetic cassette tape that can be returned to a central processing center.

Although it is expected that the recorder will be a popular tool for lightning researchers throughout the world, its first use is in an EPRI project to record surges on operating distribution lines (RP2542). A contract has been signed with Power Technologies, Inc. (with CH2M-Hill as a major subcontractor) to plan and supervise the deployment of surge recorders on three utility distribution systems. The objective is not only to gather data on lightning surges actually appearing on distribution lines but also to correlate damage to the lines with the lightning that caused it. This project is now in the initial planning stage; the intention is to select three areas of different lightning frequency incidence and storm character for the recorder installations. EPRI expects to continue the recording and damage correlation efforts over three full lightning seasons. If the lightning cooperates, we will have a good data base of surges and how they affect distribution system operations.

This project is one more step toward our ultimate goal of improving lightning protection practices and reducing the damage from lightning. *Project Manager: Herbert Songster*

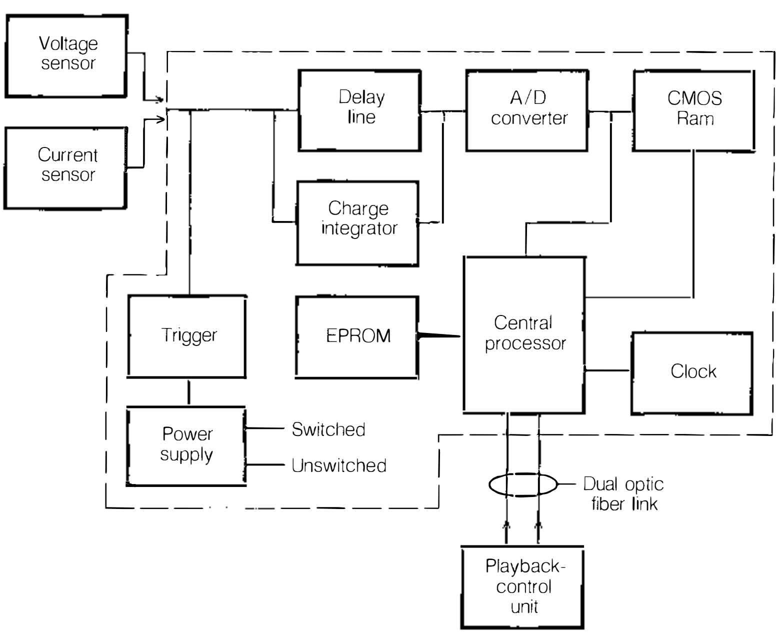


Figure 1 To avoid the possibility of introducing unwanted transients from the secondary power system, battery charging is not provided. Therefore, only essential circuits are continuously energized. Incoming transients trigger the power supply to switch on the recording circuits, while the delay line holds the transient until powering-up is completed.

Electric meter tampering detector

In 1982 EPRI undertook a project to develop a device that would give clear indication of meter tampering activity (RP1779). In the early part of the project, researchers determined from the responses to a questionnaire that the vast majority of tampering cases involve either removing the meter or glass cover in ring-type installations or removing the socket cover of ringless installations. Consequently, EPRI directed its efforts toward the development of a device that would respond to these actions.

From a group of about 20 potential detection concepts, two were selected to carry to the prototype stage and eventually to field trials. In each case, an indicator, discernible from the distance from which the meter can be read, is mounted on the inside face of the transparent meter cover. Removal of the cover, meter, or socket cover activates the nonresettable indicator.

For the field trials, only the version that responds to socket cover removal was used. The intent was to evaluate the concepts, as well as to install what was considered to be the more-complicated trigger mechanism.

Florida Power & Light Co. and Puget Sound Power & Light Co. each installed 50 meters containing the indicator. In addition, Northern States Power Co. performed the evaluations using retrofit kits.

During the time that the indicators were under regular surveillance by the two participating utilities, only one of the indicating meters was tampered with. In this case the meter cover was removed from the scene.

As a result of the field installation, valuable comments and suggestions were received from the utilities involved. The project is now over, and the final report should be available shortly. *Project Manager: Herbert Songster*

TRANSMISSION SUBSTATIONS

Analysis of transmission line transients

The recording and analysis of transmission line transients could aid the development of ultrahigh-speed relays that are capable of operating within a fraction of a cycle.

The transients used in this project (RP1422) were measured on a 15-channel, 100-kHz recording system built by Westinghouse Electric Corp. (RP751) and installed at two Florida Power & Light Co. stations. One system was installed at the 500-kV Andytown substation and operated between July 1980 and December 1982. The other system was installed at the 138-kV Lauderdale substation in February 1979 and removed in August 1983. There are plans to resume some data collection at the end of 1984 or early 1985.

The analysis of the data is being performed by Westinghouse and two other institutions, University of Pittsburgh (RP1422-1) and Rensselaer Polytechnic Institute (RP1422-2). The final report from RP1422-1 has now been received; it deals mainly with the quality of the data and the development of suitable algorithms for ultrahigh-speed relaying (UHSR) systems. This study was affected by some availability problems with the recording system and noise in the measured data. The noise content of the data was high because of the high sampling frequency and some early problems with fiber optic data links. Extensive coverage of all transient parameters, therefore, was not undertaken.

The study showed, however, that data from conventional relaying transformers were not suitable because the time constants of the CCVTs were very long and the current transformers introduced distortion. Unshielded cables also introduced significant high-frequency noise. Because of the quality and paucity of the measured data, it was necessary to complement the recorded data with data produced through computer simulations.

It is essential to identify a fault within 4 ms for UHSR and in considerably less time than this for fault current limiting devices. Some of the UHSR algorithms considered satisfied these conditions for lines shorter than 250 mi (400 km). No fault detection is possible for some of the studied relay concepts when a disturbance is already in progress. Because it was concluded that none of the relays studied were capable of performing accurately under all situations, parallel processing by using several complementary high-speed relays is considered a possibility.

For better UHSR performance the report recommends the following.

- Improved conventional relay transducers and instrumentation
- Improved knowledge of transients, especially from staged tests
- Improved simulation models capable of reproducing transients
- New algorithms capable of fault detection by using information from only one location
- Better identification of lightning surges to avoid confusion with fault-initiated traveling waves

For additional information on this work, see *EPRI Journal,* July/August 1978, p. 55; May 1980, p. 47; and June 1981, p. 41. *Project Manager: Selwyn Wright*

PLANT ELECTRICAL SYSTEMS AND EQUIPMENT

Electrical machine constants

Recently completed EPRI projects, RP1288 and RP1513, developed generator simulation models by using finite-element (FE) techniques. The project included validation of finite-element-derived models by test. As a first step in reduction to practice, methods were developed for improved representation of machine saturation (saturation functions) for steady-state reactances; these saturation functions have been designed for use in conventional power system simulation programs.

Nonlinear, magnetostatic FE calculations have enabled researchers to accurately reproduce the steady-state operating characteristics of turbine generators, including the effects of saturation in both the d axis and the q axis. However, it is not practical to incorporate calculations of this complexity in on-line conventional generator simulation programs. To take advantage of FE accuracy, simplified algorithms were developed for quickly reproducing the reactances predicted by the FE methods. These algorithms are suitable for use in conventional simulation programs. It is expected that the FE-based reactances will yield more-accurate predictions of steady-state operating points than do conventional saturation functions now used in power system simulation because these programs now apply a single saturation correction to both d- and q-axis reactances based on open-circuit-saturation data.

To properly validate the method, EPRI solicited member utility participation. Two utilities responded: the Tennessee Valley Authority (TVA) and Arizona Public Service Corp. (APS). A generator owned by each utility was analyzed, and steady-state load data were measured by each utility for validation of the resultant saturation functions. Load measurements were obtained on the Bull Run high-pressure unit of TVA and on the Cholla No. 4 unit of APS.

Good agreement between analytic and test results was obtained. The field current predictions for both generators were within 1.5% of those measured. The bulk of the predicted load angles for Bull Run are within 1.5° of those measured. For Cholla, the load angles diverge under large leading power factor conditions (the Cholla test data covered a greater range than those of Bull Run). However, the maximum deviation is 3°, and most of the Cholla-calculated load angles are within 1.5° of those measured.

These results indicate that FE-based saturation algorithms can produce initial load point predictions that are significantly more accurate than those obtained by using conventional saturation functions. *Project Manager: D. K. Sharma*

Stator slot wedge tightness measuring instrument

In recent years there has been a significant increase in hydrogenerator failures resulting from damage to the stator insulation caused by vibrations of improperly installed stator slot wedges. The present method of inspecting for loose wedges is by a tap test. This method is highly subjective, however, and can lead to significant error. A project was initiated with Vintek, Inc., to develop and demonstrate an instrument to measure wedge tightness that would be portable and more reliable than previous methods (RP2308-3).

The instrument that was developed relies on ultrasonic techniques to determine ultrasonic resonance damping, which can be directly related to wedge tightness. The electromagnetic shaker in the instrument probe head vibrates through a broad frequency range in less than a second. If the amplitude peak exceeds a predetermined value, it indicates a tight and, therefore, a good wedge.

Field tests of a prototype instrument at Rocky Reach Dam in the state of Washington and at Round Butte Dam in Oregon indicated that the instrument works well. However, because the instrument works on resonance amplitude only, a resonance frequency detection feature has been added, and the instrument has been made more portable as well as user-friendly. Additional evaluation by two utilities in the Pacific Northwest produced favorable response. The final report, EL-3358, is available from the Research Reports Center. *Project Manager: D. K. Sharma*

Power angle instrument for large synchronous machines

One conventional method to measure power angle is the use of a stroboscope directed at a point, typically a chalk mark on an exposed shaft. The method is crude and on some machines nearly impossible to implement. Hence, the object of this project was to design, develop, build, and test an instrument to measure the relative internal power angle of synchronous generators (RP2308-5).

The power angle instrument that was developed relates armature voltage-zero crossings (used as a reference) to a signal derived from rotor position. A voltage proportional to the angular difference between these signals is developed and drives a digital readout, FM tape, and flash or chart recorder. The design is suitable for any generator having a toothed wheel and reluctance-type pickup. The instrument has been thoroughly tested both in the laboratory and in the field with excellent results. It is suitable for both transient and steady-state measurements and has both digital and analog output of power angle. Because the unit may be installed as a permanent monitoring device, it has to be self-calibrating; this feature is being incorporated into the instrument in an extension of this project, which should be completed by the end of 1984.

The final report, EL-3667, contains schematics, parts lists, and drawings, which would enable any utility to assemble such an instrument for its use. *Project Manager: D. K. Sharma*

POWER SYSTEM PLANNING AND OPERATIONS

Analyzing high-speed transients

During the last 15 years a computer program called EMTP (electromagnetic transients program) was developed by the Bonneville Power Administration (BPA) and others to study high-speed power system transients conveniently and cheaply. Because EMTP grew rapidly, however, it is unable to study many phenomena of interest, is inadequately documented, and is difficult to use. A well-developed, easy-to-use EMTP could save utilities up to 90% of the disturbance analysis costs now contracted to consultants because of the lack of in-house capability. Moreover, the greater flexibility of doing studies in-house helps ensure that important scenarios are not overlooked.

EPRI has begun a three-year effort to make EMTP more useful to EPRI member utilities (RP2149). In a coordinated effort with six utility organizations in the United States and Canada (the Development Coordination Group, or DCG), a wide range of enhancements will be made. First to be addressed is the pressing need for better documentation. In 1985 two background documents, an EMTP primer and an EMTP theory reference, will be completed. An improved EMTP users manual will also be published. Work is under way on four other volumes, which (when completed in 1986) will complete a comprehensive, seven-volume set.

A variety of improvements to EMTP software are also planned. Based on surveys and interviews with over 70 utilities, 18 enhancements were recommended. Documentation, simplification of program input and output, improvement of such models as transformers and loads, and program validation against field test recordings were identified as high priorities. A complete description of these recommendations is contained in EPRI EL-2668.

The first EMTP version incorporating the above-described improvements funded by EPRI and DCG will be available from the Electric Power Software Center in mid 1985. New versions will be released periodically thereafter. *Project Manager: James V. Mitsche*

A quantitative measure of system stability

The transient stability simulation program is a basic tool used to test the performance of system plans or to calculate system limits (e.g., intercompany transfer limits) for a specific operating condition. The primary result obtained from a stability program is a plot called a swing curve that shows whether the system generators are stable or unstable for a chosen disturbance.

An experienced analyst can examine the curve and get a qualitative sense of how far it is from the point of instability. Other displays of program output (power angle plots) can also give this qualitative appraisal. From this information, decisions are made on which condition to study next. Three to eight conditions must be tested to obtain the desired result.

A numerical index showing the degree of stability or instability would make such programs more useful. The number of program executions could be reduced, margins in limit calculations could be set more confidently, and staff productivity could be increased. Researchers at Iowa State University (ISU) have successfully developed a method to calculate such an index (RP2206-3).

This new method is based on energy balance techniques used in direct stability analysis (EPRI EL-1755). Generator inertias, power, and speed at each time step are read from a traditional stability program into ISU's new computer program, STABIN. Numerical indexes indicating degree of stability or instability of each generator are then calculated. From these indexes, generators are categorized as very unstable, just unstable, stable but stressed, or stable and not stressed. From these results, the engineer can quickly obtain the answer. EPRI estimates that this capability will reduce the traditional tests or cases to two, a saving of a factor of 2–4.

The technique has been tested on several large, realistic systems. The software, available from the Electric Power Software Center in 1985, interfaces with the Philadelphia Electric Co. (Peco) stability program (which users must modify to add several "write" statements). A complete description of the research results, information on interfaces to the Peco and other programs, and limits of the technique are contained in the final project report, which will be published in the second quarter of 1985. *Project Manager: James V. Mitsche*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Vice President

FUEL INVENTORY MODELING

Inventory management is one of the key ways in which utilities can match fuel availability to requirements. Fuel inventories make it possible to carry on power generation with relative independence from daily fuel supply conditions. They also help utilities minimize costs that increase with the frequency of purchases, and they provide a hedge against shortages resulting from uncertainties in either fuel supply or electricity demand. In addition, adequate inventories allow utilities to smooth out the fuel supply variations associated with seasonal demand and irregular delivery schedules. This report reviews work by the Energy Resources Program and the Decision Methods and Analysis Program to develop a modeling system for utilities to use in managing fuel inventories (RP2314).

Several events that occurred during the 1970s have made fuel inventory planning more difficult. Oil supplies were disrupted twice; electricity demand was much lower than expected; and fuel prices increased and became more variable. Table 1 shows that from 1973 to 1982 the size of coal inventories held by utilities doubled and oil stockpile levels increased by one-third. Because of changing fuel use, however, coal inventories rose only from about three months to three and one-half months of average normal consumption, while oil inventories rose from two to six months. Because of increases in inventory levels and fuel prices, the total amount of capital tied up in coal and oil inventories rose from $1.2 billion in 1973 to $9.3 billion in 1982.

To control inventories and minimize costs, fuel managers can vary the timing and quantity of deliveries, make purchases on the spot market, and sometimes adjust generation dispatch. Traditionally, inventory management has been based on experience and judgment. Only a few utilities now use formal models to examine the trade-offs between the costs of holding inventory and the costs of inventory shortages. However, the informal approach is starting to be questioned by both utilities and regulatory commissions.

During 1983–1984 EPRI, working closely with several utilities, undertook a research project to develop an inventory modeling system (RP2314). The objective was to provide the utility industry with broadly applicable analytic tools for use in establishing cost-effective fuel inventory policies. Several phases of the project have been completed. The modeling system has been designed and a version developed for a mainframe computer. Case studies are under way at Consumers Power Co. and Tampa Electric Co. and will be completed by the end of the year. During 1985 a version for desk-top computers will be developed, and additional case studies will be conducted. The project has provided useful insights about the fuel inventory problem, some of which are discussed below. The modeling system will be available for utility application by the beginning of 1985 through the Electric Power Software Center and TEAM–UP.

Table 1
UTILITY FUEL INVENTORIES

	1973	1982
Total coal inventories		
Average level (10^6 t)	87	173
Days of average consumption	82	106
Value (10^9 \$)	0.75	5.99
Total oil inventories		
Average level (10^6 bbl)	89	120
Days of average consumption	58	175
Value (10^9 \$)	0.41	3.31

Source: U.S. Energy Information Administration, *Monthly Energy Review*, September 1983. DOE/EIA-0035(83/9).

Nature of the problem

There is a great deal of diversity in fuel inventory problems among utilities. To understand the nature of this diversity, EPRI began by looking at the physical process of fuel inventory management, including the information available to fuel managers and the decisions that managers make. Two main factors underlie the fuel inventory problem: uncertainties about supply and about bum. Were it not for these uncertainties, fuel deliveries could always be scheduled in advance to meet burn requirements exactly, and the inventory management problem would be reduced to taking advantage of price fluctuations.

Many factors contribute to fuel burn and fuel supply uncertainties. Obviously, there is a large difference in burn variation between baseload and peaking plants. Typically, power plant burn requirements are also affected by such factors as weather, season, planned maintenance, and forced outages. As for fuel supply, transportation complexity is an important contributor to variability. Other factors include labor strikes, seasonal delivery patterns, weather, oil disruptions, and changing market conditions.

There are three major cost elements involved in inventory decisions: fuel purchase costs, inventory holding costs, and shortage costs. Shortage costs are incurred when burn must be reduced because of inadequate fuel supplies. The costs of fuel shortages depend on a utility's alternatives to reducing burn (e.g., changing the dispatch order, buying power from another utility, or increasing spot market purchases) and are typically higher for a peaking plant than for a baseload plant.

Expected fuel purchase costs are usually insensitive to inventory size. Expected inventory holding costs typically increase linearly with inventory size. In contrast, the risk of incurring shortages decreases as inventories increase. Maintaining least-cost inventory levels involves balancing inventory holding costs and possible shortage costs.

Conceptual framework

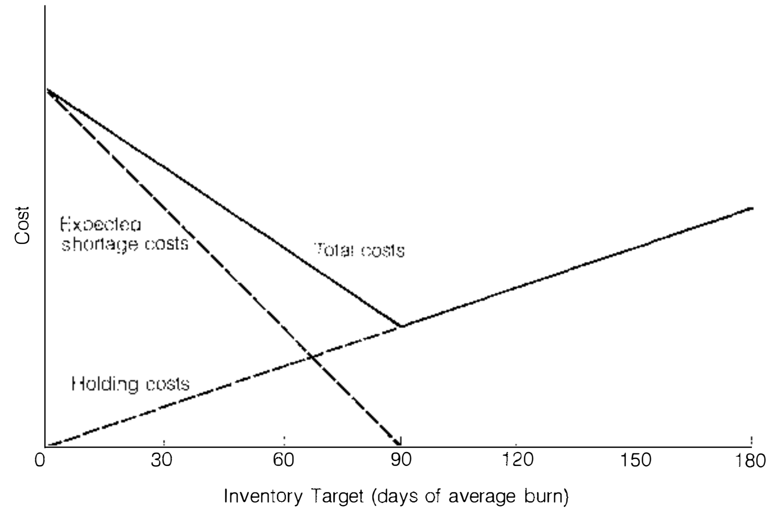
Although the EPRI inventory modeling system is detailed and moderately complex, the principles that underlie it are simple. To help explain these principles, Figure 1 presents a highly simplified conceptualization of the framework and illustrates the inventory policy–cost relationships for a simple hypothetical example. This case assumes that the burn rate is constant (which in many situations is a reasonable assumption for baseload plants) and that there is a chance of a 90-day supply cutoff once every 10 years.

As noted above, holding costs increase linearly as the inventory target level increases. Expected shortage costs are defined as the costs incurred during a fuel shortage times the probability of the shortage. If the cost per unit of fuel shortage (the unit shortage cost) is constant, the shortage cost curve will be a negatively sloped straight line. For this example it is assumed that the unit holding cost (H) is \$6/t-yr, the unit shortage cost (S) is constant at \$100/t, and the probability of supply cutoff (P) is 0.1/yr.

Least-cost inventory policy depends on the relative magnitude of the slopes of the holding and shortage cost curves, as determined by the values of H and PS, respectively. If H is greater than PS, then the costs of holding inventory outweigh the benefits, and the optimal inventory level is zero. However, if H is less than PS—as it is in this example (6 versus 10)—the optimal inventory level is exactly 90 days of burn. Note that the relationship between H and PS can be used to define a critical ratio H/S. If P is greater than H/S, then holding costs are less than expected shortage costs.

Figure 1 provides insights both about the effects of the likelihood of a supply disruption and about the effects of a disruption's duration. The shortage cost curve is very sensitive to the probability of a supply disruption. The optimal inventory level will be zero as long as P is below the ratio H/S, and it will jump to 90 days of burn when P exceeds this critical ratio. The shortage cost curve is also sensitive to the duration of a supply cutoff but in a different way. If it is assumed, for example, that the duration is 100 days instead of 90 days, the slope of the shortage cost curve does not change. Instead the curve shifts to the right, and the optimal inventory level becomes 100 days of burn.

Figure 1 This simplified example illustrates the important policy and cost relationships in fuel inventory analysis. It assumes that the burn rate is constant and that a 90-day fuel supply disruption will occur, on average, once every 10 years without warning. Key parameters are the probability and duration of the disruption and the inventory holding and fuel shortage unit costs.



Although actual applications of the model are considerably more complex than this simple example, the basic principles remain the same. The framework illustrates an interesting and important aspect of fuel inventory analysis. The inventory issue can be compared to buying insurance. There are two basic questions: Do you want to insure (build inventory)? If so, how much insurance (inventory) should you buy (hold)? The answer to the first question is sensitive to the probability of disruption. If the chance of disruption is believed to be so high that holding an inventory is cost-effective, then the answer to the second question is determined by how long the disruption may last.

Progress to date

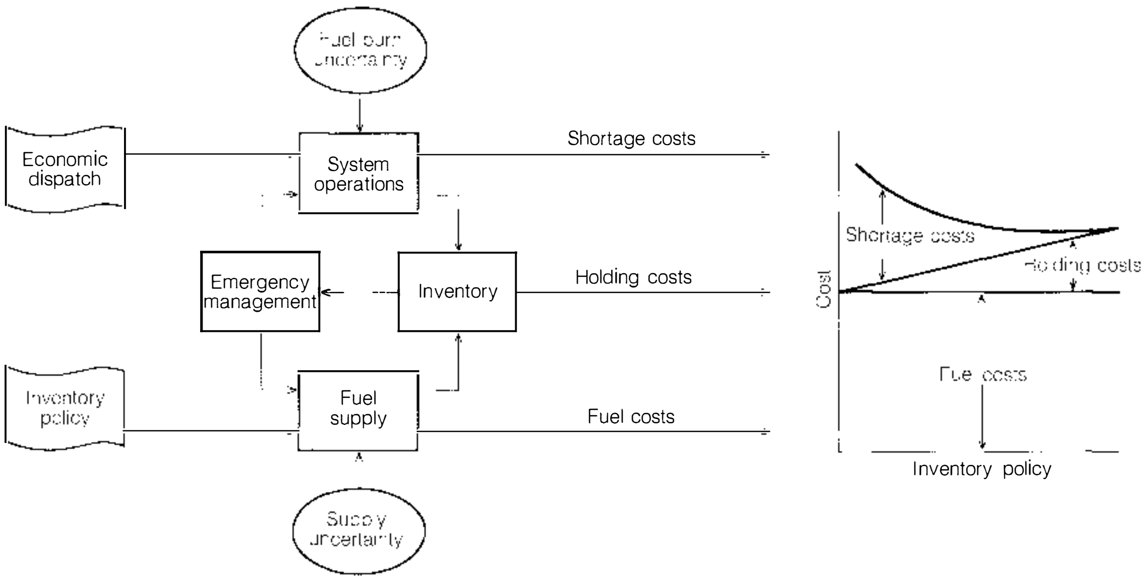
A modeling system has been implemented to handle a very diverse set of problems, including uncertain fuel deliveries and fuel burn; seasonality; emergency management; a variety of supply disruptions in terms of severity, warning, and possible duration; and nonlinear shortage costs. The modeling system features a flexible core model (Figure 2) that can be extended by incorporating the characteristics of specific utility systems. The modeling approach is based on a hybrid of stochastic simulation and dynamic programming techniques.

The modeling system has undergone extensive sensitivity testing that used data from cooperating utilities. This effort has produced major insights in two areas. One concerns the feasibility of applying a generic inventory policy to a wide variety of power plants; the other concerns the factors that underlie the need for inventories at baseload and swing-fuel plants.

Least-cost inventory levels are sensitive to the likelihood and duration of supply disruptions; in some cases, burn uncertainty can also be important. The levels can also be sensitive to the emergency alternatives that are available during a disruption. Given the diversity of conditions within the utility industry, it is unrealistic to expect that there is a generic answer to the inventory policy question even for individual companies.

The inventory problem is fundamentally different for baseload and swing-fuel power plants. For baseload plants the possibility of supply disruptions is the dominant factor that drives the need for inventories. Variation in fuel burn has an insignificant impact on the least-cost inventory policy unless the probability of a supply disruption is very small. For swing-fuel plants the relative importance of fuel burn variation and supply uncertainty is reversed. These are plants characterized by low or zero burn and a small probability of high levels of burn—for example, old coal or oil plants that follow nuclear units in a system loading order. The main determinants of least-cost inventory policy for such plants are burn uncertainty and

Figure 2 EPRI fuel inventory model. Given the economic dispatch order and an inventory target level, the model can develop estimates for fuel purchase, inventory holding, and shortage (burn reduction) costs. On the basis of the cost relationships shown in the graph on the right, utility analysts can use such estimates to determine the least-cost inventory policy.



the time it takes to increase fuel deliveries in response to increases in fuel burn.

Applications of the inventory modeling system by electric utilities have provided, and will continue to provide, a wealth of information about short-term fuel management. Insights from the case studies are being documented and will be available from EPRI by the beginning of 1985. During 1985 the utility advisory group will be expanded and will become a users group. *Project Managers: Hung po Chao and Stephen Chapel*

HISTORICAL LAKE ACIDIFICATION

This past year EPRI has started a major paleoecological study to determine the recent history of lake water acidity, measured by pH, in four regions of the United States (RP2174-10). These regions were selected because they are thought to be vulnerable to acidification by atmospheric deposition. Researchers are inferring historical pH levels for a given lake by examining the remains of unicellular plants preserved in the strata of the lake bottom sediment. To calculate the age of the sediment strata, they are using measurements of the distribution by depth of several substances (e.g., lead 210, cesium-137, charcoal, and pollen) in the sediments. The study is scheduled to be completed in 1986.

To what extent have lakes in regions assumed to be vulnerable to acidification by atmospheric deposition undergone changes in acidity during the recent past? This is a major question raised by policymakers and scientists seeking to understand the relationship between acidic deposition and the acidity of surface waters.

One approach to answering this question is to compare past and present water quality measurements. This approach contains many difficulties and uncertainties. For example, because the regions considered vulnerable to acidification are remote, there are very few historical measurements for comparison. Further, the measurements that are available tend to be poorly documented with respect to when taken, location in lake, quality control, and methods used for chemical analysis. As current experience has shown, the pH of a lake's surface water can differ considerably from that of deeper water, lake pH can vary dramatically between seasons, and certain methods of measuring pH can introduce systematic biases.

Short of inventing a time machine, is there a way researchers can estimate historical acidity levels? Each year a new layer of material is deposited on the bottom of a lake, increasing the thickness of the lake's sediment. Thus the sediment is composed of a series of strata, each stratum laid down at a different time. The deeper the stratum, the older it is. If some property of the strata can be correlated with lake water pH at the time the strata were formed and if some other property can be used to make an absolute determination of age, then a historical record of lake pH can be reconstructed. Because some of the properties being studied (e.g., the remains of algal cell walls) are related to the ecology of the lakes and others (e.g., pollen) are related to the ecology of the surrounding forests, this approach falls into the general field of research known as paleoecology.

Under RP2174-10 EPRI has recently initiated a study called PIRLA—paleoecological investigation of recent lake acidification. The objective is to improve paleoecological methods for reconstructing historical records of lake pH and to apply these methods to 5–10 lakes in each of four regions thought to be vulnerable to acidification by atmospheric deposition. The four regions are the Adirondack Park area of New York state, northern New England (including lakes in Maine, Vermont, and New Hampshire), the northern Great Lakes states (including lakes in Minnesota, Wisconsin, and Michigan), and northern Florida. A parallel study for eastern Canada is being funded by the Canadian federal government. Investigators in the two studies have agreed to use identical experimental protocols and enter their data into a unified data base.

Methodology

To determine how various substances are distributed by depth in lake sediments, PIRLA researchers are examining sediment cores 10 cm in diameter and 50 cm long. Historical pH is inferred from diatom remains (Figure 3). Diatoms make up a class of unicellular algae with cell walls composed of silica. When the diatoms die, the cell walls become incorporated into the sediment. The species of diatoms living in a lake at the time a particular stratum of sediment was deposited can be identified by visual inspection of the cell walls in the stratum.

The presence of individual diatom species is dependent on lake water pH. By surveying diatoms in a group of lakes that at present span a broad range of pH within a region, researchers can develop a quantitative relationship between diatom species and pH for that region. If it is assumed that the same relationship prevailed in the past, then the stratigraphy of diatoms in the sediment of a given lake can be used to calculate a historical record of pH for that lake.

Although diatom analysis is the principal means being used in PIRLA to determine historical pH, the feasibility of using other unicellular algae known as chrysophytes is being evaluated. Chrysophytes leave scales composed of silica in lake sediment. A possible advantage of chrysophytes is that they all live in the open water, whereas most diatoms in acidic lakes live on the bottom in the shallower areas; hence pH inferred from chrysophyte remains may be more representative of the pH of the water body.

The dating of sediment strata is based on the stratigraphy of a number of different substances. These include lead-210 (Pb-210), cesium-137 (Cs-137), pollen, charcoal, and polycyclic aromatic hydrocarbons. Pb-210 is a naturally occurring radionuclide with a half-life of approximately 22 years. It is constantly being produced in the atmosphere by the decay of radon gas (Rn-222 to be specific), which is a member of the decay series of naturally occurring uranium-238. Pb-210 is constantly being deposited on the earth's surface from the atmosphere. With time, the amount of deposited Pb-210 in each buried stratum of lake sediment decreases as a result of radioactive decay. By measuring the depletion of Pb-210 with sediment depth and using its decay constant, researchers can date the strata.

Cs-137 is a fission product of nuclear explosives, and the sediment depth at which its peak concentration occurs can be correlated with the time of peak aboveground nuclear bomb testing. Changes in the concentration of pollen from individual plant species can be correlated with times when major changes in plant distribution are known to have occurred. For instance, ragweed (species of *Ambrosia*) increased tremendously in areas of America when the forests were initially cleared by settlers. Hence strata in which the amount of ragweed pollen rises dramatically can be correlated with the time of European settlement in an area. Charcoal in lake sediment can be correlated with known dates of large forest fires. The greatest sediment depth at which polycyclic aromatic hydrocarbons of anthropogenic origin occur can possibly be correlated with the times these substances were first produced.

For accurate dating, the sediment must have been laid down with minimal mixing between strata; also, the distribution of the substances being used to date the sediment must not have been altered by biological, chemical, or physical processes after the strata were formed. These conditions require rigorous checking before a lake is selected for paleoecological analysis.

In addition to the substances already mentioned, others being measured are aluminum, titanium, silicon, potassium, sodium, magnesium, calcium, iron, manganese, copper, zinc, lead, vanadium, carbon, nitrogen, hydrogen, and sulfur. Changes in the concentration of these substances with depth may help explain patterns of historical pH. For instance, titanium and silicon concentrations generally reflect erosional processes in a watershed and therefore may indicate a land use change. Changes in sulfur, lead, copper, and vanadium concentrations may reflect changes in atmospheric deposition. In essence, we have a giant jigsaw puzzle, with the pattern of each substance for each lake representing a different piece. Through an integrated analysis of all the pieces, we will attempt to recreate the total historical picture.

A mathematical model that was developed in EPRI's integrated lake-watershed acidification study (ILWAS; RP1109-5) to simulate pH values under different environmental conditions may help researchers interpret historical patterns. On the basis of assumptions about what environmental perturbations occurred in the past, the model can simulate pH values for the lakes under study. Researchers can then test the veracity of the assumptions by comparing the simulated pH patterns with the pH patterns indicated by paleoecological analysis.

Paleoecological analysis is not without problems when it comes to evaluating the significance of estimated pH changes with time. The estimation of a historical pH pattern for a lake includes many potential sources of error; for example, errors can occur in dating,

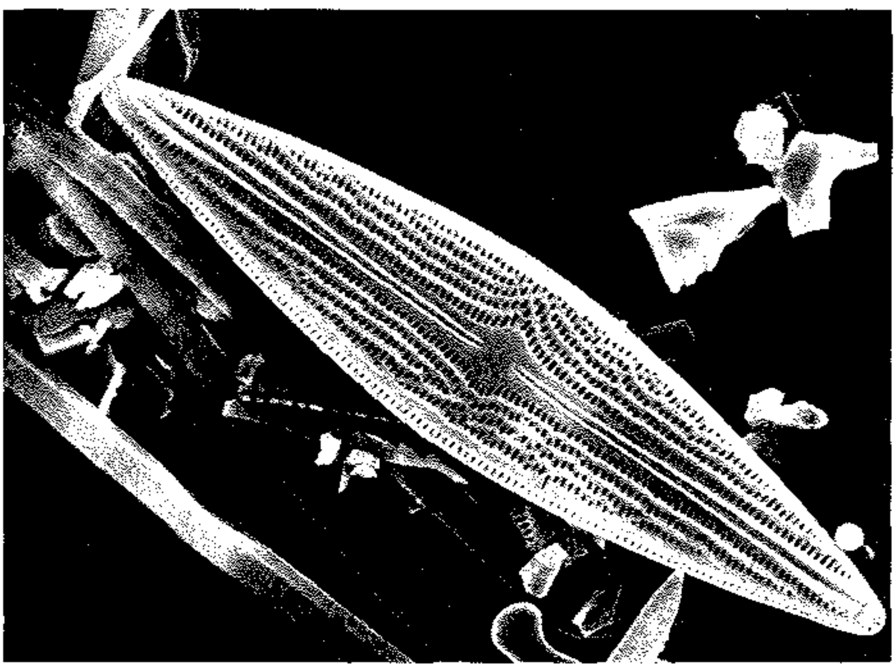
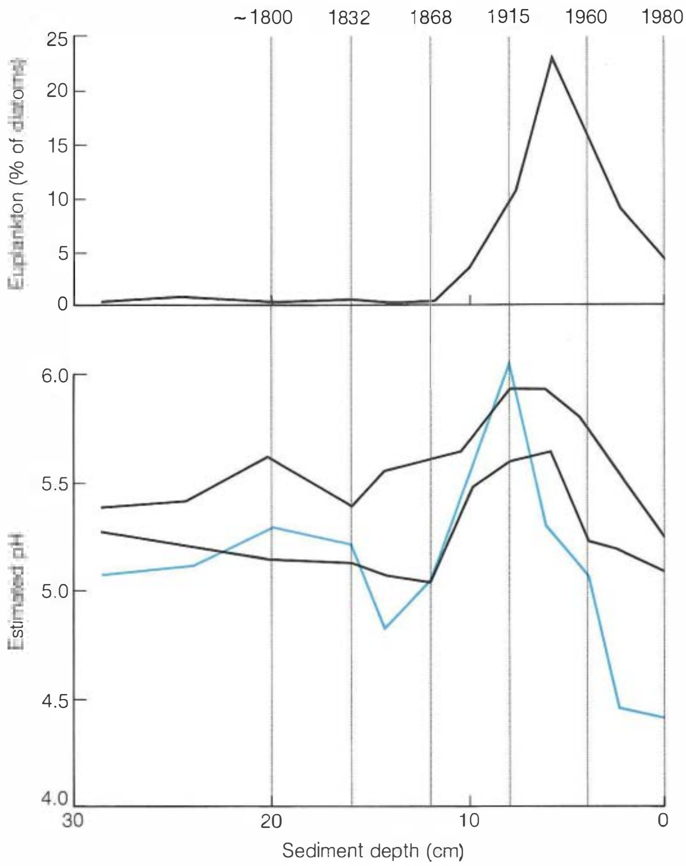


Figure 3 Scanning electron micrograph of a valve (half of the cell wall) of a diatom from the species *Anomoeoneis serians serians* (× 25,000). This is an acidobiontic diatom—that is, one generally found in lakes with a pH below 5.5. This sample comes from the sediment of Big Moose Lake in the Adirondacks. (Micrograph courtesy of Rudolph Turner, Department of Biology, Indiana University.)

Figure 4 Historical pH reconstructions for Woods Lake. A sediment core was taken from the lake, and the strata were dated by measuring the distribution of Pb-210 with depth. Estimated pH values are based on the abundance of diatoms in the sediment strata. To arrive at these values, researchers used three different mathematical pH-diatom relations (bottom graph); they also examined the stratigraphy of euplanktonic diatoms (top), which are rarely found in Adirondack lakes with a pH below 6.



in determining diatom stratigraphy, and in correlating diatom abundance with pH. How should these errors be accounted for in assessing the final uncertainty associated with the reconstructed pattern of pH? What is the best way to express the uncertainty, and how can estimates of statistical significance be used to determine if present-day pH values differ from historical values? Answering these questions is, itself, an important research facet of PIRLA. It is anticipated that the study will develop major new mathematical procedures for assessing uncertainties in pH reconstruction and in dating.

Example of pH reconstruction

As part of ILWAS, paleoecological analyses were used to reconstruct the pH history of three lakes in the Adirondacks. The results for Woods Lake, an acidic lake, are presented in Figure 4. Three different mathematical relations were used to calculate pH from the diatom stratigraphies—hence the three different reconstructed pH histories shown in the bottom graph. The top graph indicates what percentage of the diatoms in the strata are classified as euplanktonic (true open-water inhabiting). In the Adirondacks euplanktonic diatoms are rarely found living in lakes with a pH below 6.

The three pH curves and the euplanktonic diatom curve are consistent in indicating an increase in lake pH starting in the middle of the last century and peaking in the early to middle part of this century. Then pH declines to the present, when it reaches a level comparable (given the potential errors in analysis and the variability of lake pH observed during ILWAS) to its prepeak level.

PIRLA is analyzing an additional 10 lakes in the Adirondacks. The results will be compared with those from ILWAS to judge the generality of the inferred pH patterns. *Project Manager: Robert A. Goldstein*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

ADVANCED FUEL CELL TECHNOLOGY

The shorter-term objective of EPRI's fuel cell research program is to place 7.5–11-MW phosphoric acid fuel cell units into utility use. When introduced, these power plants will have heat rates of about 8000–8300 Btu/kWh at end-of-life and will be able to use any clean liquid or gaseous fuel (light distillates, methanol, propane, natural gas, or clean coal-derived gas). The advanced fuel cell technology subprogram has two major objectives: (1) to further improve the heat rate of the phosphoric acid cell to ~7500 Btu/kWh while exploring ways to reduce its stack component cost and (2) to develop the molten carbonate fuel cell, which offers lower system cost and an improved heat rate. An earlier EPRI Journal *report (September 1983, p. 55) discussed work on the improved phosphoric acid cell. This status report discusses the development of the molten carbonate fuel cell.*

The molten carbonate fuel cell has two utility applications: as modular, dispersed units that reform hydrocarbon fuels to hydrogen internally and have a 6000–6500-Btu/kWh heat rate when using clean fossil fuels or as units integrated with coal gasifiers and bottoming cycles for central stations with a 6800-Btu/kWh coal-ac heat rate (RP1085, RP2344, and RP1041).

Internal-reforming fuel cells

From an engineering viewpoint the primary advantage of the molten carbonate fuel cell is that it operates at 600–650°C. Its temperature is high enough to supply not only all the steam required for reforming but also the heat necessary for the reforming process itself. Thus the fuel cell does not need a separate reformer, and all fuel-processing operations (except desulfurization) can be carried out in the cell's anode compartment if a suitable steam-reforming catalyst is used. From the systems viewpoint the cell behaves as if it used methane directly, and it is therefore much more efficient (and simpler) than a phosphoric acid unit fueled by natural gas by means of a separate reformer. For example, the potential thermodynamic efficiency of a molten carbonate fuel cell power plant operating on natural gas at 0.73 V is 63.9%, based on the high heating value (HHV) of the gas used in the cell. A phosphoric acid fuel cell plant would have an efficiency of 41% under these conditions.

Figure 1 is a flow chart of a simple system that uses natural gas directly. The cell will probably use at least 85% of the natural gas rather than 100%, giving a minimum total efficiency of 54%, based on the fuel HHV. Other losses in a power plant will reduce this by 2–3 percentage points. This efficiency is still almost 10% greater than that of a phosphoric acid system at the same cell potential because of losses in the external fuel-processing system.

The rates of all physicochemical reactions increase with temperature, so polarization

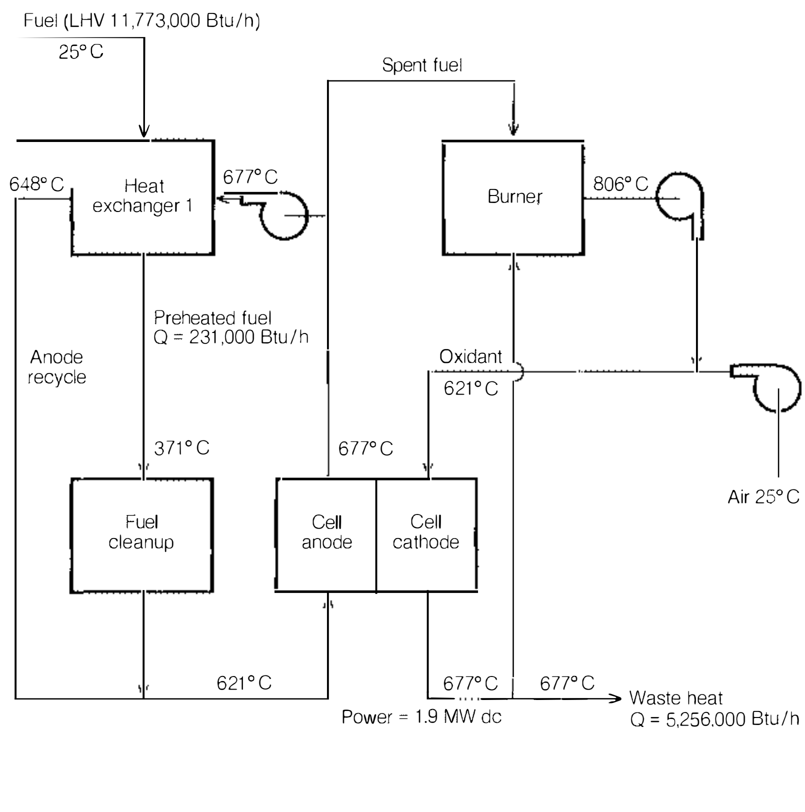


Figure 1 Direct natural gas molten carbonate fuel cell power plant, system configuration 1.

losses are less at 650°C in molten carbonate than at 200°C in phosphoric acid. At 650°C, oxygen molecules can react with the O^{--} ions in the carbonate melt to give peroxide (O_2^{--}) and superoxide (O_2^-) ions or their carbonate complexes. These compounds are reversibly reduced at the cathode, giving very rapid oxygen kinetics compared with those in phosphoric acid. Recent studies at the Illinois Institute of Technology show that on a planar electrode the equilibrium kinetic rate of the oxygen electrode in carbonate melt is ~10 mA/cm^2, about that of the hydrogen electrode (RP1085-2). Consequently, little polarization occurs at the anode and cathode because of slow electrode reaction (activation polarization). Losses result mainly from diffusional gradients and internal resistance. The important point is that these losses can be minimized by good cell design.

Systems aspects of internal reforming

EPRI-sponsored research (RP1041) studied internal-reforming molten carbonate efficiency, cost, and systems in the 2-MW class (EM-3307). Energy Research Corporation (ERC) and Fluor Engineers, Inc., examined five system configurations (Figure 2). The simplest arrangement (system 1) recycled hot fuel and oxidant streams at atmospheric pressure and required only one 35-ft^2 (3.25-m^2) heat exchanger. System 2 was similar but pressurized. System 3, another atmospheric pressure unit, used fresh steam injection for reforming, giving higher gas partial pressures and thus slightly better efficiency than system 1. Systems 4A and 4B were modifications of system 3 to allow the use of natural gas containing thiophene. Off-the-shelf chemical engineering components were used as much as possible in the evaluation; for example, in system 1, the high-temperature blower was the only exception.

System performance was calculated assuming strict input impurity levels (0.1 ppm by volume sulfur entering the cell) with an inverter efficiency of 97% and parasitic power losses of 5% of rated output. The cell potentials were estimated by using a simple model for dependence of polarization on reactant pressures. Figure 2 shows the system HHV efficiencies under similar operating conditions (160 mA/cm^2, 90% fuel utilization). System 1 has a calculated voltage of 0.73 V per cell under these conditions, corresponding to a system HHV efficiency of 53%. Because the more complex systems show little improvement over system 1, it was chosen as the baseline. This work has been confirmed by an extensive computer analysis of internal-reforming cells developed by Physical Sciences, Inc., under RP1085-5 and RP1085-9, provided the cells have thin, low-resistance electrolyte layers and use high-performance off-eutectic electrolytes (WS 78-135).

This study shows that dispersed generators with heat rates of 6550 Btu/kWh (HHV) are possible if development problems associated with making durable, low-cost, high-volume components can be solved. These generators would be smaller, simpler, and more efficient chemical engineering systems compared with phosphoric acid cells. Fluor estimated plant costs of $900/kW (not including installation), assuming nonautomated assembly and stack costs of $300/kW of active area—$16/lb, compared with average material costs of $3/lb—(EPRI EM-3307). Higher efficiencies (to 5900 Btu/kWh) may be obtained if higher capital costs can be justified (more-complex systems, carbon dioxide transfer devices, or operation at lower current densities).

Development problems

Although ERC has successfully run internal-reforming single cells, these cells do not have the electrolyte management problems characteristic of stacks. United Technologies Corp. (UTC) recently developed pressurized laboratory-scale stacks (~3 kW) using low-Btu gas in conjunction with DOE and Niagara Mohawk Power Corp. projects (RP1273). These stacks performed excellently with very little dispersion between cells over 1000–2000 hours. Cells at the negative end of the stack then start to flood, and those at the positive end lose electrolyte. This transfer results from electroosmosis along the manifold gaskets. Researchers now understand the electrolyte migration and are reducing it by careful cell edge-seal, manifold seal, and stack design. However, the problem cannot be entirely eliminated. Electrolyte migration affects only the electrolyte inventory of the last five cells at each end of a stack, and large stacks, with their greater electrolyte inventory per unit of edge-seal length, will greatly reduce migration effects. Practical stacks may require suitable

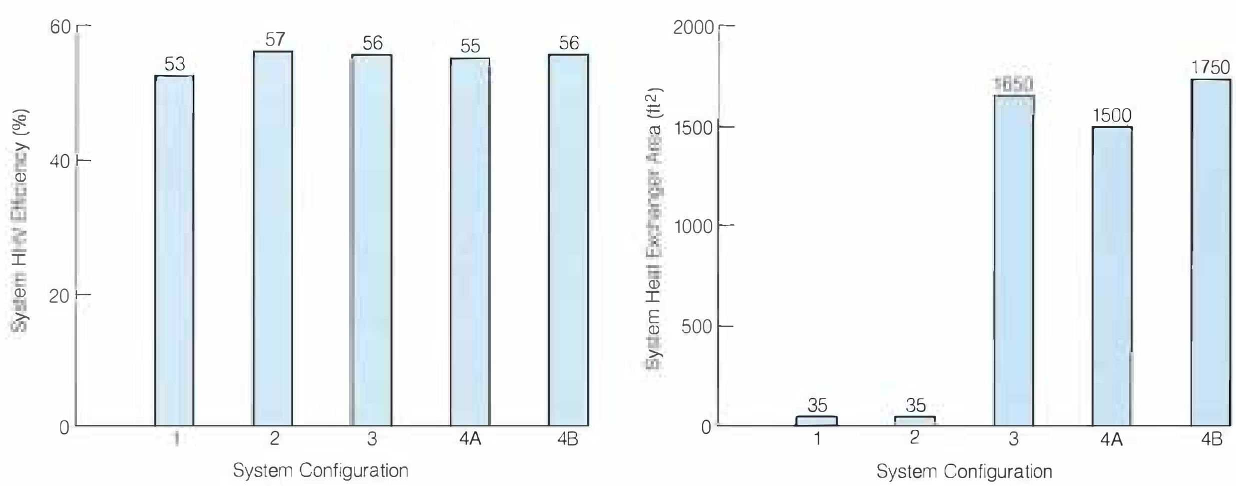


Figure 2 Relative efficiencies and heat exchanger area requirements for the molten carbonate direct fuel cell power plants studied (90% fuel use, 160 mA/cm^2).

reservoirs at each end to maintain the correct electrolyte inventory and composition throughout the stack.

Materials problems in today's cells include anode creep, cathode current collector corrosion, reforming catalyst contamination, and slow cathode dissolution. These problems occur in varying degrees and can be controlled with available materials, with the possible exception of slow cathode dissolution. Other problems, such as recrystallization of the lithium aluminate electrolyte binder and exflorescence of lithium chromite in the sintered nickel–10% chromium anode, have already been solved. Electrolyte loss by evaporation is still another problem that research has eliminated. Measurements made at the Institute of Gas Technology show that evaporation would be a major cause of electrolyte loss if the gases exiting the cell were saturated (RP1085-2). Fortunately, work done under RP1273 and RP1085 at UTC shows that the gases are not saturated, and, in fact, carbonate evaporation may only be about 10% of theoretical.

Other research is solving many materials constraints.

- Nickel or nickel-copper cermet anodes with a stable ceramic core (developed at General Electric Co. for DOE) or chromium-free modified-nickel-sintered electrodes (developed at ERC) largely eliminate anode creep.

- A film of lithium ferrite about 4 mils (0.1 mm) thick will form on the type-316 stainless steel cathode current collector after 40,000 hours, but should not be life-limiting. The stainless steel on the anode side is clad with nickel, which remains corrosion-free. The metal edge-seal areas, which come in contact with anode and cathode gases, are protected effectively from corrosion by aluminizing.

- Carbonate contamination of the internal-reforming catalyst over time will deactivate it. Although the catalyst is carbonate-resistant, it must still be protected from capillary wetting. A carbonate barrier in the form of a cermet-type anode that exposes only nickel to the electrolyte may be desirable (pure nickel is lyophobic to carbonate).

- No fully satisfactory substitute for lithiated nickel oxide at the cell cathode has as yet been found.

UTC first discovered that lithium-doped nickel oxide dissolved at the cathode under high carbon dioxide partial-pressure conditions in new-technology cells with thin tapecast electrolyte layers. These conditions would correspond to those in pressured utility cells. Investigations showed that Ni^{2+} solubility depends inversely on melt oxide ion concentration, which accounts for the carbon dioxide pressure dependence. The nickel diffuses down its concentration gradient to the anode, where it precipitates as metal (which can eventually short-circuit the cell). Dissolution effects become evident earlier in lives of cells with thin, low-resistance electrolytes, especially under high-pressure operation, and the resulting shorter lives are unacceptable for power plant use.

Researchers are examining other conducting oxides as substitutes for nickel oxide. Progress has not been very rapid because of the lack of scientific knowledge of the chemical interactions in the cathode environment. Theoretically, p-type semiconductors, such as the lanthanum perovskite family, should have high conductivities under oxidizing conditions. UTC work showed that this is so, but with the possible exception of lanthanum nickelate, p-type semiconductors are unstable in carbonates (RP1085-4). Ceramatec, Inc., has examined the n-type perovskites and related compounds—for example, calcium or strontium titanate and lead zirconate donor-doped with Nb^{5+} or Ta^{5+} (RP1085-6). These compounds are stable, but they have proved difficult to dope and/or show poor conductivity. (Doped calcium titanate, however, shows excellent stability and conductivity under anode conditions.) Ideally any nickel oxide substitute should not contain an element that can precipitate as metal under anode conditions. The best candidates would be cell corrosion products, such as lithium ferrite. Ceramatec found this compound difficult to dope consistently, but Argonne National Laboratory has recently had some success with Mn^{2+} ions. Another possible candidate is Mg^{2+}-doped lithium manganite. Argonne and General Electric (under Oak Ridge National Laboratory contract) are studying these compounds. EPRI is planning research to examine other compounds (yttrium perovskites, spinels, and certain lead compounds). An alternative solution, being examined with some success at ERC, is to slow down nickel oxide dissolution by chemical modification and by operation of internal-reforming cells at a low carbon dioxide partial pressure and at lower temperatures (average 625°C). One of these approaches is likely to be successful.

The design of a cost-effective internal-reforming fuel cell stack presents other, more practical problems. Such a design must take into account all the above factors, as well as pressure requirements for electrical contact, cell-edge resilience, sealing, creep, and anode reforming catalyst location. ERC (RP2344) and the Institute of Gas Technology (RP1085-10) are studying component design and assembly requirements for a cost-effective internal-reforming stack. A prototype stack should be in operation in 1987–1988 so that the 6500-Btu/kWh fuel cell can be available in 1995. *Project Manager: A. J. Appleby*

HYDRO INFORMATION EXCHANGE

The hydroelectric community has a wealth of practical information that could be used to resolve the variety of issues that limit the fullest use of the hydro resource. However, this community has not had a means of exchanging its information. Diverse plant ownership, remote locations, insufficient incentives, and competitive attitudes impede information exchange. Urged by utility advisers, EPRI has taken the first step in overcoming this communications problem. The Institute will spend small amounts of money to develop ways of expediting information transfer. If successful, this modest EPRI effort could save the utility industry and its customers millions of dollars.

The United States has nearly 1600 hydro power plants with a capacity of about 80,000 MW and an output of over 300 billion (10^9) kWh—one-seventh of the country's electricity needs. These plants are owned by private utilities, municipal and state governments, six federal agencies, private industry, and, more recently, venture capitalists. Diverse ownership, as well as remote plant locations and limited incentives, results in a kind of isolation. Exchange of information and experience has been almost nonexistent. However, sound technical arguments for dealing with environmental isues make information exchange necessary. For example, environmental regulations reducing plant output by 2–5% could cost the nation about half a billion dollars annually. Further, information exchange may improve maintenance practices that could result in greater plant availability. A 1% improvement in availability would save $150 million annually. Costs and savings of this magnitude require cooperation to achieve maximum output and to avoid duplication of work.

EPRI, together with its hydro advisers, is playing a key role in hydro information exchange. EPRI's advisory group is composed of individuals from organizations generating most of the U.S. hydroelectric energy. The advisers are from all types of organizations, including the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, three other federal agencies, three state agencies, seven private utilities, and a rural coop. This advisory group has consistently stressed the importance of and need for information exchange within the hydroelectric community.

EPRI is responding to the industry's communication needs in two ways. First, the Institute is developing guides based on individual and organizational experience and knowledge. Second, EPRI is establishing a number of information channels. This report discusses these guides and channels, as well as how hydro power producers may participate in the communication process.

Experience guides

Knowledgeable contractors survey the hydro community, analyze responses, and develop recommendations and guides. A good example of this process is the work on repair of cavitation damage. The project resulted from industry recognition that cavitation damage is responsible for a substantial portion of hydro plant outage. Further, repair methods and their success have varied widely around the country. EPRI initiated a project to determine if some power producers developed effective ways to mitigate and repair cavitation damage that could be used by others.

Prime contractor Acres American, Inc., and subcontractors St. Anthony Falls Hydraulic Laboratory and Allis Chalmers Corp. sent questionnaires to many hydro power producers and visited several hydro plant sites. Investigators correlated cavitation frequency and damage with several site and turbine characteristics, as well as evaluated repair methods, their cost, and effectiveness. Acres American is using this information to prepare a guide for mitigating cavitation damage and improving repair procedures. The report will be available in early 1985.

Several other projects of this type are either complete or under way. Motor Columbus and Black & Veatch Engineers-Architects analyzed plant outage causes to learn about generic problems, common mistakes, and approaches to prevent or resolve problems. The contractors completed the project earlier this year and published a report (EPRI EM-3435).

Another such project, involving small-hydro technology transfer, is being cofunded by DOE. International Engineering Co., Inc., is investigating the experiences of small-hydro developers in planning, engineering, licensing, constructing, operating, and maintaining small-hydro plants. Because no small-hydro plant had been built for several decades, the small-hydro renaissance of the 1970s saw developers repeating common errors. International Engineering is surveying several hydro developers to document their experiences and identify successful approaches to site development. The results of this work will be published in early 1985.

EPRI and the hydro community have identified several similar projects, but lack of funds inhibits research in these areas. For example, problems in new large-hydro and pumped-hydro plants have caused costly delays in plant commissioning. Complete documentation and analysis of these problems may eliminate them and save other hydro developers and owners frustration and cost.

Communications channels

The objective in establishing communications channels is to allow complete, organized information transfer throughout the hydro community. Two approaches have been developed: a publication and conferences.

In early 1983 Tom Logan of the U.S. Bureau of Reclamation, one of EPRI's hydro advisers, suggested that the Institute promote a periodical to cover news and technology exclusively for the hydroelectric community. The committee of hydro advisers endorsed the proposal and assigned it the highest priority in EPRI's hydro program, and so it remains. After discussions and correspondence with many publishers and advisers, EPRI elected to work with *Hydro Review* to fulfill the technology information needs of the entire North American hydroelectric industry. In October 1983 *Hydro Review* and EPRI agreed to expand the publication and include large-hydro articles, technical papers, and technical news. Figure 3 shows a recent issue of the magazine. *Hydro Review* and EPRI anticipate that by 1987 the expanded version of the magazine will have established the reputation and the readership to continue without formal EPRI support.

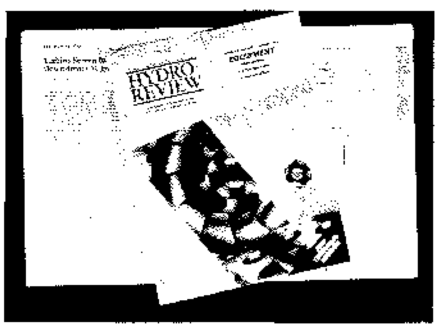


Figure 3 To disseminate the wealth of knowledge available throughout the hydro community, EPRI and the publisher of *Hydro Review* are expanding the magazine's content and developing a larger readership. EPRI members can subscribe at a reduced rate.

Hydro Review will continue to use its resources to cover the changing legal, political, and regulatory news. EPRI has funded Black & Veatch to solicit and help prepare technical articles and to report on current problems, solutions, and events of technical significance. Issues of the magazine will also have a calendar of events, reviews of key technical publications, and reports on major events.

To help the publisher meet the hydro community's information needs, EPRI and *Hydro Review* have established a publisher's advisory board. To serve on this board, EPRI selects key people for their expertise and for the diversity of their technical and organizational backgrounds. The board meets semiannually to guide and direct the magazine's technical content. The board also reviews abstracts of proposed technical articles and reviews selected final papers.

A complimentary copy of *Hydro Review* can be obtained by writing Paula L. Smith, Director of Marketing, Hydro Consultants, Inc., 755 Boylston Street, Suite 707, Boston, Massachusetts 02116. Subscriptions are $44.00 a year or $30.80 a year for individuals from EPRI member utilities.

Conferences on operation and maintenance (O&M) are another important communications channel. A conference is usually limited to a specific topic, and speakers recognized for their knowledge and experience are invited to discuss that topic. Past conferences have covered general O&M, pumped-hydro plant overhauls, and dam safety and monitoring. Readers may obtain conference information by contacting the EPRI program manager.

The hydro community has a vast resource in individual experience and expertise. Some of this information may be in internal organization reports, but little of it has reached other organizations. The industry can save millions of dollars if other individuals and organizations have access to this knowledge. EPRI encourages utilities to participate in this communication exchange. The program will not be successful unless the information is used. *Program Manager: James Birk*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

WET-STEAM E/C IN BALANCE-OF-PLANT PIPING

Carbon steel pipes that carry wet steam in both BWR and PWR systems have experienced severe erosion/corrosion (E/C) damage, necessitating costly outages and repairs. The thickness of some pipe walls has deteriorated at rates of up to 1.5 mm/yr. The piping systems most affected are the high-pressure turbine exhaust to the moisture separator reheater and the high-pressure turbine extraction steam lines to subsequent feedwater heaters (Figure 1). EPRI has sponsored research on the state of the art to determine factors causing E/C and to recommend ways of preventing or mitigating it (RP2231-1, -2).

An EPRI-sponsored survey of technical literature and numerous plant visits identified the causes of E/C in wet-steam piping (RP2231-1). Temperature, pH, oxygen level, moisture content, flow path geometry, and pipe metallurgy all influence E/C. Of these factors, pH, pipe metallurgy, and flow path geometry appear to offer the greatest practical potential for mitigating E/C. Increasing pH to 9.3 or above in all-steel PWR turbine systems has significantly reduced the E/C rate. However, this PWR water chemistry modification requires careful plant operation considerations. Further, higher wet-steam pH is not possible in BWRs because they must be operated at neutral conditions.

Carbon steel is the most commonly used material for wet-steam pipes in domestic nuclear plants. Researchers inspecting such pipes in nuclear plants have discovered that these materials are susceptible to severe E/C damage. Steel in the turbine cross-around pipes in some plants has trace amounts of alloying elements, particularly copper, which may provide some improvements in E/C resistance.

Alloying elements such as chromium and molybdenum, even in small amounts, can improve carbon steel E/C resistance. Study has shown that carbon molybdenum steel reduces E/C rates by about 3 times and chromium molybdenum steel more than 10 times the rates observed in carbon steel. Steels comprising 1¼Cr–½Mo and 2¼Cr–1Mo are virtually immune to E/C.

Flow path discontinuities, such as elbows, significantly increase localized E/C rates. Investigators found that the major contributing factor in extreme E/C damage and piping failure was poor pipe geometry. Even the use of more corrosion-resistant materials may not overcome the effects of geometry.

On the other hand, "tiger striping," a degradation of pipe inner diameter characterized by vast areas of eroded bandlike regions, is apparently not limited to flow path discontinuities. Investigators have documented significant wall loss to tiger striping in a number of straight pipe sections and not necessarily throughout the full length of the pipe. Researchers do not fully understand tiger striping, and they are continuing to study this phenomenon (RP2515-4).

EPRI has evaluated pipe repair and material replacement (RP2231-1). Localized defects are good candidates for weld repair with the same base material or a more wear-resistant alloy. This type of repair is not permanent, however, because in many instances, E/C has attacked areas adjacent to the weld even more vigorously, leaving the weld or cladding almost untouched.

Researchers evaluated a number of materials to gather useful information for making

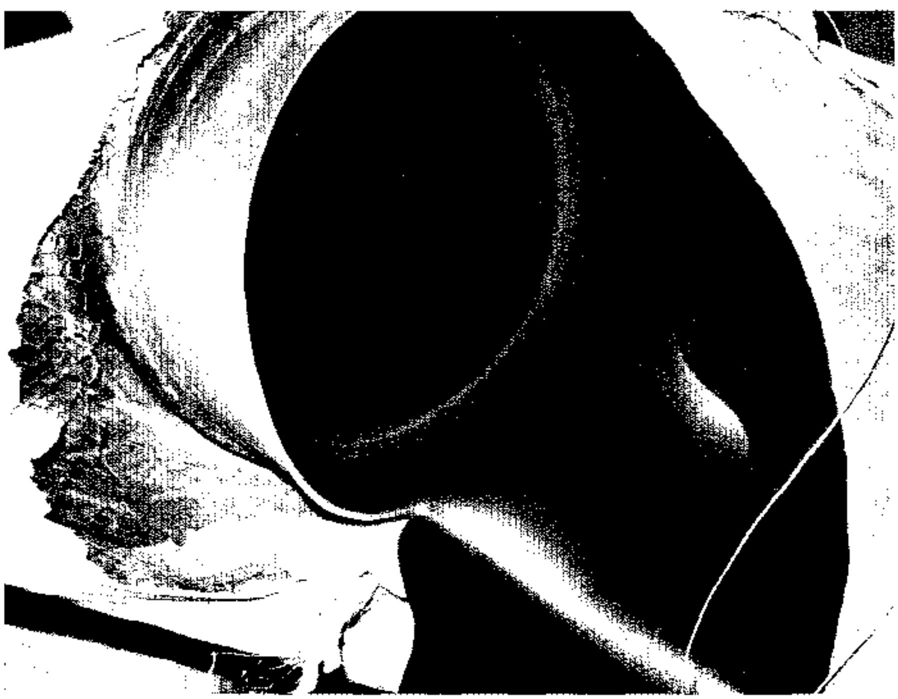


Figure 1 Severe erosion/corrosion caused this 24-in high-pressure carbon steel extraction line, tapped from the high-pressure turbine exhaust, to rupture at a 90° elbow. Researchers are studying some cost-effective methods for preventing or mitigating wet-steam erosion/corrosion.

cost-effective decisions about pipe design or replacement. Cr-Mo low-alloy and austenitic steels are E/C-resistant and should be considered design material for wet-steam turbine piping. Similar materials used as cladding could provide the same resistance to attack; however, their cost may limit the use of such cladding to repairs only.

EPRI also investigated the retrofit of a high-velocity moisture separator device to eliminate E/C damage in the turbine cross-around piping. The project objective was to determine whether such devices could be physically installed in existing plants, at what cost, and with what effect on plant performance.

Project personnel developed four single-stage reheat baseline configurations, representing both PWR and BWR installations; they held the heat input to the turbine constant for all four cases. Then they fitted each baseline configuration with a high-velocity separator (HVS) and conducted various studies to evaluate the effect of different parameters on configuration performance. In addition to modeling HVS thermal performance, they investigated the physical arrangement of the device and the cost of installing it. The project team further modified each cycle to include nonreheat and two-stage reheat configurations. In the single-stage and two-stage reheat plans, they added reheater surface to the space made available by removal of the moisture separator chevrons or mesh.

Researchers concluded that installing the HVS in typical domestic nuclear turbine systems is feasible and that for all studied conditions, its application helps heat rate. The capital cost of the installation is approximately $2 million. Replacing reheater tube bundles with 50% more surface adds $2.3 to $2.5 million. BWRs would require additional expense for decontamination and storage of radioactive material.

In all cases studied, the HVS improved heat rate. In most cases, additional reheater surface improved heat rate. Exceptions were a single-stage reheat cycle with doubled reheater surface and some of the two-stage reheat cycles with 50% more surface in the second stage. Most of the configurations also generated more kilowatts of electricity. However, some two-stage reheat cycles showed a generation loss, which was not fully compensated for by reduced fuel use.

In general, retrofitting the HVS is economically advantageous. In addition, improved moisture separation mitigates E/C in cross-around systems.

EPRI has also developed criteria and methods for an inspection program (RP2231-2). This program eliminates the need to inspect every steam pipe and fitting surface. Instead, the program examines the parameters affecting E/C and identifies pipe areas most susceptible to E/C. Using this method, inspectors can sample a limited number of pipe areas to determine the seriousness of E/C. If they find E/C degradation is serious, they would have to expand the sample.

The results of both EPRI projects, RP2231-1 and RP2231-2, will be published shortly. *Project Manager: Norris S. Hirota*

LWR AEROSOL CONTAINMENT EXPERIMENTS

Extensive international research is under way to understand the behavior of radioactive materials in both the primary system and the containment building of an LWR under postulated severe accident conditions. Early experiments on containment systems provided valuable information about the transport and retention of fission products by natural processes and about the effect of engineered safety features on fission product removal. These experiments did not, however, realistically account for very high aerosol concentrations, transient thermal conditions, and the effect of intercompartmental flows. Under RP2135-6 EPRI is cosponsoring LWR aerosol containment experiments (LACE) to characterize inherent aerosol retention processes to show that, in the event of a postulated severe accident, the threat to the public would be less than now calculated. Several international organizations have already agreed to participate in the LACE program, which consists of large-scale experiments and related support efforts, including data analysis and code validation.

The LACE program will focus on postulated high-consequence accident situations that have an inadequate data base and that are not being addressed by other test programs. It will consider situations for which severe consequences are now calculated by computer codes because (1) the reactor containment building is bypassed altogether (containment bypass sequences), (2) the containment function is impaired early in the accident (early containment leakage or failure to isolate), or (3) the postulated containment failure occurs later, simultaneously with a large fission product release involving significant aerosol resuspension or delayed core damage (delayed containment failure). Significant aerosol retention could reduce the consequences calculated for these accident situations. The LACE researchers will experimentally investigate aerosol retention and develop data for aerosol and thermal-hydraulic computer codes. The results should considerably improve our ability to realistically assess the consequences of these accidents.

To facilitate implementation and encourage international participation, the LACE effort has been divided into two parts. Large-scale experiments at the Hanford Engineering Development Laboratory (HEDL) form the base program. This work is complemented by a support program of smaller-scale experiments and analytic efforts at other laboratories.

Support program

The support program is divided into three main areas. The first entails direct support activities that are required for planning and performing the large-scale experiments. Tasks in this area include the development and implementation of aerosol generation techniques, thermal-hydraulic calculations, chemistry support, and instrumentation support.

The second area entails separate-effects tests that are necessary to clarify individual phenomena difficult to study at large scale. These tests will examine, for example, the change in aerosol behavior due to hydrogen burning, aerosol penetration of cracked concrete, aerosol resuspension mechanisms, and revaporization effects. Although peripheral to the large-scale experiments, the work on such phenomena is critical to understanding aerosol behavior in containment structures.

The third support area involves analytic efforts. A series of calculations will be required to help design the experiments, analyze the resulting data, and conduct code validation. The data analysis and code validation efforts will be organized to meet many of the objectives recommended by the aerosol experts group of the Organization for Economic Cooperation and Development's Committee on the Safety of Nuclear Installations.

Base program

The base program consists of large-scale integral tests designed to simulate various postulated accident sequences. As noted above, the tests will focus on three accident situations: containment bypass sequences; early containment leakage, including failure to isolate; and delayed containment failure.

The containment bypass test series consists of three scoping tests and two follow-on tests to study aerosol retention in interface piping, in an auxiliary building, and in leakage paths from the building. To obtain planning information, the scoping tests were initiated before the LACE program plan was finalized; the experimental conditions (which are described in the next section, along with some of the results) were based on current aerosol generation experience so that the tests could be completed quickly without additional development effort. In the follow-on tests, researchers will vary pipe diameter and gas velocity and will use more prototypical aerosol materials.

Three tests will address early containment failure. In the first, which will simulate a failure to isolate the containment, leakage will occur through a well-defined pathway to a scrubber. Aerosol behavior and retention in the containment and the leakage path will be measured. In the second test the containment will be isolated initially, then rapidly vented from high pressure to simulate early failure due to overpressure. Rainout and aerosol modification inside the containment will be studied. The third test will simulate conditions associated with containment isolation failure in order to study the effect of intercompartmental flows on aerosol behavior. Data from this test should be helpful for evaluating the well-mixed-volume assumption currently used in computer codes.

Two tests on delayed containment failure—specifically, late containment leakage due to overpressure—will study aerosol behavior under dynamic steam condensation and heat transfer conditions. The two tests will differ in the rate of aerosol injection: the maximum suspended concentration will be approximately 0.1 g/m^3 for the first test and approximately 10 g/m^3 for the second. Dynamic steam condensation and heat transfer conditions similar to those for a small-pipe-break accident will be modeled. Questions regarding aerosol resuspension will also be addressed.

The aerosols featured in the base program tests will be realistic, using materials typically found in LWR cores. Both water-soluble and water-insoluble materials will be included. Each test will help validate aerosol and thermal-hydraulic computer codes. A formalized procedure for comparing code predictions and test data will be established; it will include pretest and "blind" posttest calculations.

Containment bypass scoping tests

These tests were conducted to investigate the retention of aerosol materials in interface piping and an auxiliary building during a postulated LWR check valve failure accident sequence—designated Event V in NRC's *Reactor Safety Study* (WASH-1400). Specifically, the objectives were to measure the fraction of aerosol retained in the pipe, to identify changes in aerosol characteristics resulting from flow through the pipe, and to determine aerosol behavior (deposition, agglomeration, plate-out, condensation) in a vented auxiliary building.

According to an analysis of the Event V sequence, conditions that would normally be present include high aerosol mass concentrations, high gas velocities in the pipe, a steam-hydrogen carrier gas, a long and tortuous pipe pathway, and discharge into an auxiliary building. The following mechanisms influence particle deposition: fluid turbulence in a straight pipe, gravity settling, inertial impaction in bends, fluid turbulence downstream from elbows, Brownian diffusion, thermophoresis, and diffusiophoresis. Of these mechanisms fluid turbulence in a straight pipe and inertial and turbulent effects downstream from elbows were expected to dominate. Important auxiliary building conditions considered were volume, wall and gas temperature, pressure, the ratio of steam to noncondensable gas, the amount of superheat, aerosol residence time, and venting conditions.

Table 1 presents conditions for the three containment bypass scoping tests. Sodium hydroxide was used to simulate soluble aerosol materials formed from fission products (e.g., cesium hydroxide). Aluminum hydroxide was used to simulate insoluble aerosols formed from structural materials. The amount of steam superheat was varied to study the effects of condensation and water uptake. Important parameters kept constant during the tests included pipe geometry, gas flow rate, gas composition, and pressure drop along the pipe. The tests were performed in the HEDL Containment Systems Test Facility, whose 850-m^3 containment vessel served as the test auxiliary building.

The aerosols were produced in an aerosol generator with a burn chamber and a reaction chamber. For the sodium hydroxide aerosol, sodium was placed in the burn chamber, where it reacted with air to form sodium oxide; steam was then added to the reaction chamber to convert the sodium oxide to sodium hydroxide. For the aluminum hydroxide aerosol, preformed particles of hydrated alumina were dispersed in an air stream by a jet pump and injected into the reaction chamber. Reactions and mixing were completed in the generator before the aerosol was discharged through the test pipe.

Table 1
CONDITIONS FOR CONTAINMENT BYPASS SCOPING TESTS

Parameter	Test 1	Test 2	Test 3
Aerosol			
Species	$NaOH$	$NaOH$, $Al(OH)_3$	$Al(OH)_3$
Injection duration (min)	60	60	60
Carrier gas thermal-hydraulics at test pipe inlet			
Steam mass flow rate (kg/s)	0.14	0.14	0.14
Air mass flow rate (kg/s)	0.19	0.23	0.26
Nitrogen mass flow rate (kg/s)	0.08	0	0
Total volumetric flow rate at 0°C, 101 kPa (m^3/s)	0.38	0.35	0.37
Gas velocity (m/s)	100	91	97
Gas temperature (°C)	186	111	160
Pressure (kPa)	210	179	181
Steam fraction by volume	0.45	0.48	0.46
Steam superheat (°C)	88	15	66
Reynolds number	4×10^5	4×10^5	5×10^5
Test pipe			
Inside diameter (mm)	63	63	63
Length (m)	27	27	27
Number of elbows	5	5	5
Pretest pressure drop (MPa)	0.1	0.08	0.1
Test auxiliary building			
Volume (m^3)	850	850	850
Initial temperature of wall and gas (°C)	85	81	84
Pressure (kPa)	101	101	101
Vented	yes	yes	yes

When the preestablished test conditions were met, the inlet valve to the test pipe was opened. The aerosol, air, and steam mixture was then swept through the test pipe, exiting into the vented containment test vessel that represented the auxiliary building. Following the 60-minute injection period, the inlet valve to the test pipe was closed and aerosol generation was terminated. Aerosol behavior was monitored at the pipe inlet and outlet and throughout the test vessel during the injection period and for 22 hours afterward.

Researchers measured the aerosol airborne mass concentration, particle size, and deposition rate as functions of time by collecting and analyzing filter, cascade impactor, and deposition samples. They also monitored pipe and vessel temperatures, pressure in the aerosol generator and the vessel, the composition of the vessel atmosphere, and the carrier gas flow rate. Steam fractions in the pipe outlet and vessel atmosphere were measured, along with the rate of steam condensation on the vessel walls and the total condensation in the vessel. The amounts of sodium and aluminum deposited in the pipe and the vessel were determined by posttest cleaning, and an overall sodium and aluminum mass balance was made at the end of each test. Visual observations and photography were also used.

A major objective of the LACE program is to provide data for computer code validation. As part of this effort, aerosol retention code calculations have been completed for containment bypass conditions representative of the Surry plant, one of two plants used as case studies in WASH-1400. These same codes will be used for "blind" posttest calculations, and the results will be compared with the containment bypass scoping tests.

Atmospheric conditions in the vessel were nearly the same during all three tests. At the start of aerosol injection, the test vessel was at steady state, with water vapor saturating the atmosphere and condensation occurring on the slightly cooler walls. During the injection period, the vessel's atmosphere became slightly superheated.

Steam superheating in the pipe varied from test to test. During the experiments the pipe wall temperature was above the local saturation temperature, which prevented condensation from occurring anywhere along the pipe.

For the first test, the aerosol material was partially hydrated sodium hydroxide; for the second, a mixture of coagglomerated liquid sodium hydroxide and solid aluminum hydroxide; and for the third, dry solid aluminum hydroxide. It is likely that aerosols in LWR interface piping during Event V accidents would be at least partially liquid because of the presence of cesium hydroxide.

Table 2 presents the measured aerosol characteristics at the pipe inlet for the first two tests; data for the third test are not yet available. The average total aerosol injection rate and suspended concentration were higher for the first test than for the second; the aerosol particle size and standard deviation were as expected from pretest analysis.

Table 2
AEROSOL CHARACTERISTICS

Property	Test 1	Test 2
Aerosol injection rate (g/s)		
$NaOH$	3.8	0.6
$Al(OH)_3$	0	0.4
Initial aerosol size, mass median diameter (μm)	3.9	3.2
Initial aerosol geometric standard deviation	3.0	2.5
Suspended concentration at pipe inlet (g/m^3)		
$NaOH$	12	2
$Al(OH)_3$	0	1

The major results for the first two tests are very similar even though the aerosol constituents differed. In both tests deposited aerosol was probably carried along the test pipe by the high-velocity carrier gas. As a result, a large fraction of the aerosol was collected either in a larger-diameter section at the end of the test pipe or in the test vessel. For the first two tests, considerably less than 3% of the aerosol was vented from the vessel.

Although the results from the containment bypass scoping tests are still preliminary in nature and represent only two sets of test conditions, they are encouraging. They demonstrate that significant retention of radioactive aerosols could occur in the interface piping and the auxiliary building of an LWR following a postulated containment bypass accident situation. *Technical Specialist: Frank Rahn*

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 entry: 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.

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ADVANCED POWER SYSTEMS

Assessment of the Potential of Halophytes as Energy Crops for the Electric Utility Industry
AP-3679 Final Report (RP2272-7); $10.00
Contractor: Texas Tech University
EPRI Project Manager: S. Kohan

COAL COMBUSTION SYSTEMS

Nuclear Assay of Coal
CS-989 Final Report (RP983-4); Vol. 9, $11.50; Vol. 10, $20.50
Contractor: Science Applications, Inc.
EPRI Project Manager: O. Tassicker

Effect of Variables on the Fatigue Behavior of Ti-6Al-4V
CS-2934 Topical Report (RP1264-2); $16.00
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: R. Jaffee

Selective Catalytic Reduction for Coal-Fired Power Plants: Feasibility and Economics
CS-3603 Final Report (RP1256-7); $16.00
Contractor: Stearns-Roger Engineering Corp.
EPRI Project Manager: E. Cichanowicz

Fossil Fuel Power Plant Constructibility Research: Needs and Priorities
CS-3690 Final Report (RP2578-1); $16.00
Contractor: Sargent and Lundy Engineers
EPRI Project Manager: D. Golden

Comparison of Two Groundwater Flow Models: UNSAT1D and HELP
CS-3695 Topical Report (RP1406-1); $11.50
Contractor: Battelle, Pacific Northwest Laboratories
EPRI Project Manager: D. Golden

Retrofit FGD Cost-Estimating Guidelines
CS-3696 Final Report (RP1610-1); $500.00
Contractor: Stearns Catalytic Corp.
EPRI Project Manager: T. Morasky

Cyclic Reheat Materials Evaluation
CS-3700 Interim Report (RP1652-2); $11.50
Contractors: Battelle, Columbus Laboratories; Stearns Catalytic Corp.
EPRI Project Managers: R. Rhudy, B. Syrett

Monitoring the Fixed FGD Sludge Landfill—Conesville, Ohio
CS-3702 Final Report (RP1406-2); $14.50
Contractor: Michael Baker, Jr., Inc.
EPRI Project Manager: D. Golden

Characterization Tests of an Apitron Particulate Control Device
CS-3713 Final Report (RP725-12); $16 00
Contractor: Southern Research Institute
EPRI Project Manager: R. Carr

Coal-Water-Slurry Pumping and Flow Tests
CS-3722 Interim Report (RP1895-10); $14.50
Contractor: Adelphi University
EPRI Project Manager: C. Derbidge

Enhancing Fossil Power Plant Design, Operation, and Maintenance: Human Factor Guidelines
CS-3745 Final Report (RP1752-1); Vol. 1, $17.50; Vol. 2, $64.50; Vol. 3, $14.50
Contractors: Honeywell, Inc.; Monterey Power Technologies, Inc.
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Development of a Water-Jet Concrete-Cutting System
EL-3601 Final Report (RP7860-1); Vol. 1, $10.00; Vol. 2, $11.50; Vol. 3, $8.50
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EA-3606 Final Report (RP1587); Vol. 2, $13.00; Vol. 3, $11.50
Contractor: Arthur D. Little, Inc.
EPRI Project Manager: S. Braithwait

Application of Analytic Methods: Environmental Control R&D Planning Model
EA-3674 Final Report (RP2040); $13.00
Contractor: Applied Decision Analysis, Inc.
EPRI Project Manager: L. Rubin

Environmental Settings and Solid-Residues Disposal in the Electric Utility Industry
EA-3681 Final Report (RP1487-13, RP2198-7); $13.00
Contractor: Envirosphere Co.
EPRI Project Manager: I. Murarka

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Contractor: Synergic Resources Corp.
EPRI Project Manager: E. Beardsworth

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EPRI Project Manager: J. Platt

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EM-3658-CCM Computer Code Manual (RP370-26); $8.50
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EPRI Project Manager: W. Spindler

Proceedings: Commercial Refrigeration Research Workshop
EM-3699 Proceedings (RP2034-9); $10.00
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EPRI Project Manager: R. Oehlberg

BEAGL-01: A Computer Code for Calculating Rapid LWR Core Transients
NP-3243-CCM Computer Code Manual (RP1761-18); Vol. 1, $14.50; Vol. 2, $14.50
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EPRI Project Manager: G. Lellouche

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NP-3574-SR Proceedings; $26.50
EPRI Project Manager: M. Angwin

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