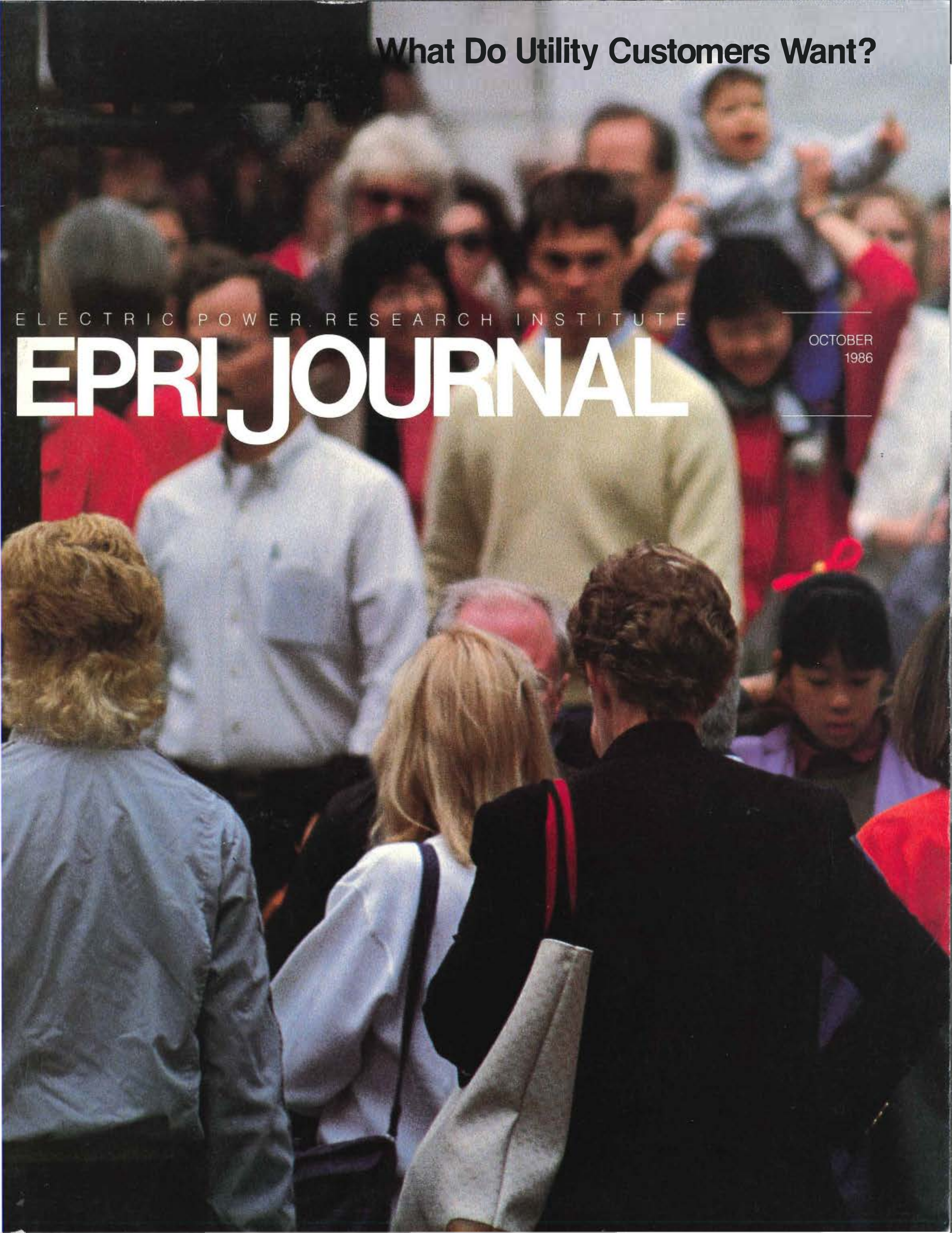
What Do Utility Customers Want?

ELECTRIC POWER RESEARCH INSTITUTE

EPRI JOURNAL

OCTOBER
1986



EPRI JOURNAL is published nine times each year (January/February, March, April/May, June, July/August, September, October, November, and December) by the Electric Power Research Institute.

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.

EPRI JOURNAL Staff and Contributors
Brent Barker, Editor in Chief
David Dietrich, Managing Editor
Ralph Whitaker, Feature Editor
Taylor Moore, Senior Feature Writer
Michael Shepard, Feature Writer
Pauline Burnett, Technical Editor
Mary Ann Garneau-Hoxsie, Production Editor
Jim Norris, Illustrator
Jean Smith, Program Secretary
Kathy Kaufman (Technology Transfer)

Richard G. Claeys, Director
Corporate Communications Division

Graphics Consultant: Frank A. Rodriquez

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

Please include the code number on your mailing label with correspondence concerning subscriptions.

Cover: The wide diversity of personal needs and wants in our society makes it difficult for utilities to decide which energy services to offer in their service areas. A new emphasis on understanding customer behavior and preferences is making utility marketing programs more responsive to more customers.

EPRI JOURNAL

Volume 11, Number 7 October 1986

The Rebirth of Utility Marketing

Gellings

In recent years there has been a marked resurgence of marketing activity by the utility industry. Some, claiming the industry has come full circle, characterize this as a return to approaches used prior to the energy crisis—a rebuilding of the programs that were dismantled in the constrained postembargo years. Nothing could be further from the truth. The volatile energy environment, constraints on supply, and the rise of competition in the 1980s have forced the industry to reevaluate its fundamental business premises. Marketing is now undergoing a metamorphosis, not a return, and the difference is grounded in the most basic of concerns—the utilities' perception of customers and their energy needs.

In past decades utilities considered their product to be kilowatthours, which were distributed to customers through meters for various end uses. It has become clear, however, that customers are more likely to see the product as energy *service* and to be responsive to such nonpower offerings as innovative billing procedures, advice on appliance efficiency, help in financing efficient energy measures, tips on reducing energy costs, and information on new energy uses. In a short time utilities have responded to this view, making the transition from selling increments of electricity to offering a broad array of demand-side management (DSM) programs and services tailored to suit particular customer needs and interests.

But how should such programs be marketed? How can service be sold most effectively? The key to these questions is captured in a definition from management guru Peter Drucker: "Marketing is understanding the customer so well that the product or service fits him and sells itself . . . the aim of marketing is to make selling superfluous." To be successful, utilities have to go beyond the question of simply how much electricity their customers are likely to buy and deal with the more subtle questions of how the customer uses energy, what types of service he expects, what his preferences are—basically, what his energy lifestyle is.

Support tools being developed by EPRI to help utilities design, market, and target their DSM programs take exactly this approach, first gaining an understanding of the energy decision process in all major customer segments and then applying it to estimate end-use technology penetration and DSM program acceptance. The result will define a marketing approach that is right for the utility and the consumer, one that helps utilities function as energy service suppliers in an increasingly customer-oriented future.

Clark W. Gellings
Senior Program Manager, Demand-Side Planning
Energy Management and Utilization Division

Authors and Articles

Gellings Lewis Karp Samm Shimshock Kennon

Understanding the Consumer (page 4) surveys the development of behavioral models in parallel with nationwide market research to help utilities build and shape electricity demand. Written by Mary Wayne, science writer, who conferred with two staff members of EPRI's Energy Management and Utilization Division.

Clark Gellings directs the Demand-Side Planning Program, the successor of demand and conservation studies that he had managed since 1982. He was formerly with Public Service Electric & Gas Co. for 14 years, becoming assistant manager for load management. Gellings has an MS in mechanical engineering from the New Jersey Institute of Technology and an MS in management science from Stevens Institute of Technology.

L. E. Lewis, a senior project manager, joined EPRI in February this year. He was briefly with Applied Management Sciences as director of utility market planning and before that was a project manager in demand-side management studies with Battelle, Columbus Laboratories. Lewis worked for 14 years in rate and market research with Consumers Power Co. He has an MA in economics from the University of Michigan. ■

The Plasma Torch: Revolutionizing the Foundry Fire (page 12) explains how an arc-induced plasma cuts energy and raw material costs as it doubles the blast temperature in a foundry cupola. Written by Taylor Moore, *Journal* feature writer, with technical input from EPRI's Energy Management and Utilization Division.

Alan Karp, who has managed research projects in electrotechnologies since 1982, was formerly a project engineer with Bechtel Petroleum, Inc. Earlier, he had carried out a number of process design and project engineering assignments at Exxon Research and Engineering Co., Imperial Oil Enterprises, Ltd., and Fluor Engineers, Inc. Karp holds BS and MS degrees in chemical engineering from Stevens Institute of Technology and the University of Michigan, respectively. ■

New Cable for the Urban Environment (page 20) introduces a new cost-cutting insulation for pipe-type transmission systems. Written by Ralph Whitaker, *Journal* feature editor, aided by two research managers in the Electrical Systems Division.

Ralph Samm joined EPRI in October 1974 and has been program manager for underground transmission since shortly thereafter. He formerly was with I–T–E Imperial Corp. for more than 16 years, becoming R&D manager for gas-insulated cable projects. Samm has a BS in electrical engineering from Johns Hopkins University and an MBA from the University of Pittsburgh.

John Shimshock has worked in cable research, design, and operation for almost 30 years. An EPRI project manager since October 1976, he is also site manager of the Waltz Mill (Pennsylvania) Underground Cable Test Facility. From 1958 to 1976 he was with New Jersey's Public Service Electric and Gas Co. Shimshock has a BS in electrical engineering from Pennsylvania State University. ■

Transmission Line Design at Your Fingertips (page 26) reviews the growing use of an expanding library of specialized software that integrates electrical and mechanical criteria for overhead towers and lines. Written by Jonathan Cohen, science writer, with assistance from the Electrical Systems Division.

Richard Kennon has managed a program of overhead transmission lines research since 1978. He joined EPRI in 1975 as a manager of substation research projects after nearly 23 years with Westinghouse Electric Corp., where he was manager of capacitor equipment engineering. Kennon received a BS in electrical engineering from California Institute of Technology and an MBA from Indiana University. ■

I want comfort and convenience.

Safety is my top concern.

No power glitches for my computer!

I'd like to lower my energy bills.

Plenty of power when I want it.

Just keep my TV and VCR running.

I need help financing a home insulation project.

Can you give me advice on energy efficiency?

Prompt service is a must.

UNDERSTANDING THE CONSUMER

Behavioral models based on new understanding of consumer preference and interest are providing insights and sharpening marketing approaches for utility demand-side management concepts.

What do utility customers want? Just asking the question signals a basic shift in the way that electric utilities approach the marketplace. In the past, programs were designed to match utility objectives, then offered to customers. Today, utilities are beginning to integrate the customer's wants and needs into the program planning process.

Public attitudes toward the purchase and use of energy-consuming equipment are not the same as they were before the energy dislocations of the 1970s. Neither are the available choices. Understanding how people make energy choices in the 1980s and beyond is vital to utilities because their customers are rapidly gaining access to more options than ever before.

For example, on-site generation of electricity by end users, still confined mostly to the industrial sector, accounts for about 4% of U.S. consumption. This practice could grow and spread to other sectors as small package cogeneration systems and new technologies make power production by end users more feasible. Power imports from Canada and Mexico have doubled since 1980, from 1% to 2%, and the natural gas industry has stepped up spending in a strong bid to increase its market share.

Electric utilities have responded to this rising challenge, in part, with a move toward demand-side management (DSM). DSM aims to modify electricity purchase patterns in a way that will benefit both utility and customer. Successful DSM could help utilities cut peak loads by 10–12% over the next 20 years, build efficient loads, and pass $60–$100 billion in savings along to their customers, according to Clark W. Gellings, manager of EPRI's Demand-Side Planning Program.

The snag is that successful DSM efforts require customer participation, and participation is usually voluntary. If customers fail to take part, then the whole string of potential benefits unravels. Utilities have been puzzled to find that customers sometimes shun DSM programs even when offered attractive economic incentives.

"Viewing the customer's interest in DSM as concerned solely with minimizing cost is simplistic," explains Gellings. "A more realistic view is that although utilities are concerned with electricity price relative to production cost, customers are concerned with electricity price relative to value." Value has to do with satisfying a variety of energy service needs, including comfort and convenience, as well as economy.

To grasp the real forces that shape utility customer behavior, Gellings stresses the need to suspend assumptions and gather actual data. "That's the difference between selling and marketing," he says. "Selling starts from the company's assumptions about what the customer will buy. Marketing first gathers information about the customer's preferences, then uses this information to determine what products or services to offer.

"Making this shift might look difficult for electric utilities, because utilities need quantifiable data for planning, and marketing information has long been considered too qualitative, too subjective to be of use to planners. That's changing, though. New research techniques in marketing can provide the quantitative data required for program planning."

Understanding how utility customers make energy purchase decisions and how utilities can influence those decisions is the thrust of a major new EPRI project on customer preference and behavior. The multiyear effort began in late 1985 and is scheduled to continue through 1989. The EPRI budget is $3.2 million, to be supplemented by an additional $1–$2 million in cofunding from participating utilities. L. E. Lewis, EPRI senior project manager with the Demand-Side Planning Program, is overseeing the project.

The new project addresses customer acceptance of DSM initiatives, as distinguished from customer response. *Acceptance* is the decision to sign up for a program or buy an appliance. *Response* refers to the impact of these energy purchase decisions on the utility load shape. Although EPRI is actively pursuing research in both areas, gaining customer acceptance is the focus of the research evolution traced here.

First steps

"Our current work is an outgrowth of the knowledge gained from a series of earlier project insights," reports Lewis. Beginning in the late 1970s, EPRI researchers began probing customer attitudes toward utility conservation and load control programs. What would it take to get customers to participate in these DSM programs, providing the utility with an alternative to costly capacity expansion?

One project looked at customer participation in programs for direct utility control of air conditioners and water heaters. The conclusion was that a high level of marketing—specifically, direct customer contact—was the key to gaining high acceptance rates. For the 10 air conditioner control programs that did intensive marketing, the median participation rate was approximately 70%, whereas those with minimal marketing achieved an adoption rate barely over 10%.

The size of the targeted group turned out to be very important in facilitating face-to-face contact. For example, Cobb Electric Membership Cooperative in Georgia achieved an impressive 76% participation rate in its air conditioner load control program by personal contact promotion. For utilities with large urban service territories, this performance suggested a lesson: break down the marketing effort by neighborhoods or communities to preserve possibilities for personal contact and to allow the development of a critical mass of program acceptance among customers in the target area. Such early insights laid the groundwork for later development of more-precise and refined market segmentation techniques.

What about financial incentives? Conventional wisdom held that DSM programs could not succeed without some form of monetary compensation to customers. But project findings did not entirely support this belief.

Among the 23 Buckeye Power, Inc., distribution cooperatives, three systems out of the five that obtained adoption rates of over 70% for direct load control of water heaters offered no financial incentives at all. The majority of successful programs did offer some payment, however, which suggested that incentives, though not essential, could give the marketing effort a strong boost. The size of the incentive seemed to make little difference.

The first attempt to systematize such observations into a predictive model came during related work under EPRI's *Rate Design Study*. Researchers took an existing market model that linked customer attitudes to buying behavior and began adapting it to the decision to buy, or accept, a utility load control program. Consistent with utility findings, a simple model predicted that many customers would accept direct load control without an incentive—at least 20%, and in some cases as many as 75%.

These early efforts showed that customer behavior could be quantified and modeled. They also showed that both promotional activities and monetary incentives could affect that behavior. Marketing clearly worked, but some marketing approaches seemed to work better than others. Which ones, and under what conditions?

A formal framework for this inquiry emerged in the DSM primer cofunded by EPRI and Edison Electric Institute. That project categorized marketing implementation methods into six types: customer education, direct customer contact, trade ally cooperation, advertising and promotion, alternative pricing, and direct incentives. It furnished a common language for utility research in marketing.

Experience had already shown quite different rates of effectiveness for the various techniques. For example, customer education by means of bill stuffers proved a poor choice for marketing load control programs, typically yielding participation rates below 5%. Direct mail worked better; a single mailing usually recruited about 10%, and multiple mailings around 18% of those solicited. Subsequent research would reveal that customer education, to be most effective, should be used in sequence with other marketing steps.

Just making customers aware of DSM programs (a necessary prelude to participation) could be a challenge. In EPRI's survey of utility experiences implementing DSM programs, Southern California Edison Co. reported that 468 telephone interviews with residential customers yielded only 15% who recalled hearing the utility's radio ads. With prompting from the interviewer, the figure rose to 28%, and of those, 80% recalled the load management message. These results showed how important it was to gauge the impact of specific marketing methods on specific target audiences.

At the same time, researchers were discovering that each marketing method was best suited to specific situations in terms of buyer readiness and barriers to customer acceptance. For example, at the early stages of a decision process, customer education could raise customer awareness of an innovative technology, such as a high-efficiency heat pump. Once a customer reached the purchase stage, direct financial incentives were very powerful in overcoming the barrier of high first costs.

Using various combinations of the six marketing methods, most utilities were successful in implementing their DSM programs. In one group studied, Ohio Edison Co. gained 65 MW of new load in one year; Illinois Power Co. achieved incremental sales of $2.5 million in the same period; and Minnkota Power Cooperative, Inc., was able to improve its load factor by 15% over a period of seven years.

But implementation guidelines were still very general, leaving utilities with a number of unaided choices to make in promoting DSM. Doubts lingered among utilities, even those with successful programs, as to whether they were getting the best results for their marketing dollars.

The turning point

By the mid 1980s, industry marketing efforts had reached a watershed. An array of techniques were available, and the results were sometimes impressive, yet they were still inconsistent. Finding the right approach for the right audience remained to some degree a matter of trial and error. What else could be done to make DSM program marketing better focused and thus more cost-effective?

The answer was implicit in the industry's emerging DSM philosophy. If de-

Perception of Customer Values

Utilities have assumed reliability and cost of service to be the top priority for their customers. Research has shown, however, that customers are more interested in the value of the electricity service for their specific end-use needs. Thus, for the residential sector, the major customer concerns are reflected in lifestyle services, such as comfort and convenience, in addition to cost minimization.

Utility-Perceived Customer Values

Reliability

Cost

Quality

Power on demand

Convenient billing

Prompt service

Safety

Actual Customer Values

Comfort

Convenience

Control

Appearance

No hassle

Caring for me

Economy

mand was not a given, then surely customer behavior, the root of all demand, could not be considered a given either. It was time to take the final step: to turn the process around and start over with a sharp focus on customers—who they were, what they wanted, how they made energy purchase decisions. Collecting and analyzing this information would allow utilities to move beyond selling their programs to customers and begin to truly market them. It would make the difference between using a shotgun approach and using a laser beam.

This shift from selling existing programs to developing better focused programs gave birth to EPRI's current customer preference and behavior project, which exemplifies the new approach. Researchers have begun with the customer's viewpoint, the heretofore missing link in utility market planning. The idea is to discern the customer's needs, then see how they can be matched with the utility's needs to create programs that serve the interests of both parties.

Project goals are fourfold. They are to develop refined models of the customer decision-making process; to collect data on customer beliefs, attitudes, and characteristics so that utilities can use the models effectively; to tailor the models and methods in case studies with selected utilities; and to transfer the resulting knowledge to utilities in easily usable form.

Key concepts in that effort are customer choice modeling and market segmentation. The first addresses the question, "How do utility customers make their energy purchase decisions, and what affects those decisions?" The second deals with a question vital to targeting customer programs, "Who are our customers, and how do they differ from one another in ways that might affect program acceptance?"

Simulating customer decisions is a relatively new idea for utilities. But customer choice modeling is likely to gain ground as customers are faced with more and more options as to the type, amount, and supplier of the energy they use.

A family of models will embrace different customer sectors. For example, the driving factors for the residential model may be comfort, convenience, and cost, and the major constraints the existing appliance stock and the household budget. Commercial/industrial customers, on the other hand, are influenced most strongly by cost and constrained by the need to comply with government regulation in their energy purchases. Builders and architects make up a third group whose choices about energy systems in new or remodeled structures can strongly affect utility sales.

Residential data will come from the project's in-depth, face-to-face survey of 800 randomly selected households nationwide. Interviewers will ask utility customers about their energy needs and preferences, as well as their appliances, income, age, and education. Surveys of 800 commercial/industrial customers and 400 builders/architects will round out EPRI's national data base.

Market segmentation specifies target groups based on these customer characteristics. The first step is usually to break the utility market down by customer class. Some utilities have gone further and segmented each customer class by end use or by demographic features.

For example, commercial/industrial customers may be segmented by the size of their demand. But "demand level or even load shape is too coarse a characteristic," says Gellings. "There is really no evidence to suggest that customers with the same demand level or load shape, particularly in the commercial class, have similar wants and needs. In fact, many utility programs have had disappointing results because their segmentation stopped at this level.

"Or take the case of segmentation by income level in the residential sector. Do we really believe that a young professional making $30,000 a year and a blue-collar family with the same income have the same energy lifestyle? Their energy needs and consequent purchase behaviors are probably quite different. We're gathering better data on customers to allow more-precise market segmentation based on customer needs as well as on demographic characteristics."

To see how well the new models work in actual utility settings, nine host utilities across the country have expressed interest in cofunding detailed case studies of the models' application in their DSM market planning: Carroll Electric Membership Corp., Georgia Power Co., New England Electric System, New York State Electric & Gas Corp., North Carolina Alternative Energy Corp. with Blue Ridge Mountain Electric Membership Corp., Northeast Utilities, Pacific Gas and Electric Co., St. Joseph Light & Power Co., and San Diego Gas & Electric Co. Another 40-plus utilities will participate in the data-gathering phase of the project.

Final products will be diverse. Foremost are the decision models and the national data base to be furnished to utilities. In addition, there will be a series of guidebooks, videos, and technical reports to support utilities in getting maximum use from the research. "Because our participating utilities are eager to begin using these new tools, we're stressing early deliverables," comments Lewis. "We're giving them all we can as we go along instead of waiting to deliver everything at the end of the project in 1989."

Perhaps the most intriguing part of the transfer effort is the EPRI software created for personal computers. This package will allow a utility planner to calibrate a customer decision model for his own service territory by adding utility-specific information; feed in data from the EPRI-supplied data base; look at DSM programs with various combinations of features; and for each of these candidate utility programs, estimate the rate of customer participation. Output comes in graphic form with supporting numbers for easy presentation.

A software demonstration diskette is available for simulating an electric dryer or space-heating program. Consistent with the project's emphasis on customer needs, EPRI is actively involving its participating utilities at an early stage in expressing design preferences and giving feedback after hands-on trials with the software they will be using.

Preliminary findings

Launched in late 1985, the project is already beginning to yield some insights about customer preference and behavior that have emerged during the groundwork for the national residential survey. "One of the first things we've noticed," reports Lewis, "is that customers will put more time and thought into buying an appliance with a lot of features than one with just a few, regardless of the financial impact of the decision. For example, they often will take longer to decide about a $500 refrigerator—what color? frost-free? icemaker? glass or wire shelves?—than about a $2500 furnace system replacement. For a fairly simple device with few options like a water heater, they may call their plumber and let him install whatever he has on the truck."

A second finding is that customers classify energy choices differently than utilities might expect. "Customers often don't perceive energy products or services in the same way that utilities do. They may group them or split them apart, based on their own needs and priorities," Lewis explains. "For example, utilities may divide space heating systems into electric and gas, whereas the end user may lump those two together as clean systems and distinguish them from dirty heating fuels, such as wood, oil, or kerosene. Or customers may classify some items, like microwaves, as convenience purchases as distinguished from essential purchases, like a kitchen range. It's important that we understand the customer's perspective and incorporate that into our program planning efforts."

Market Segmentation

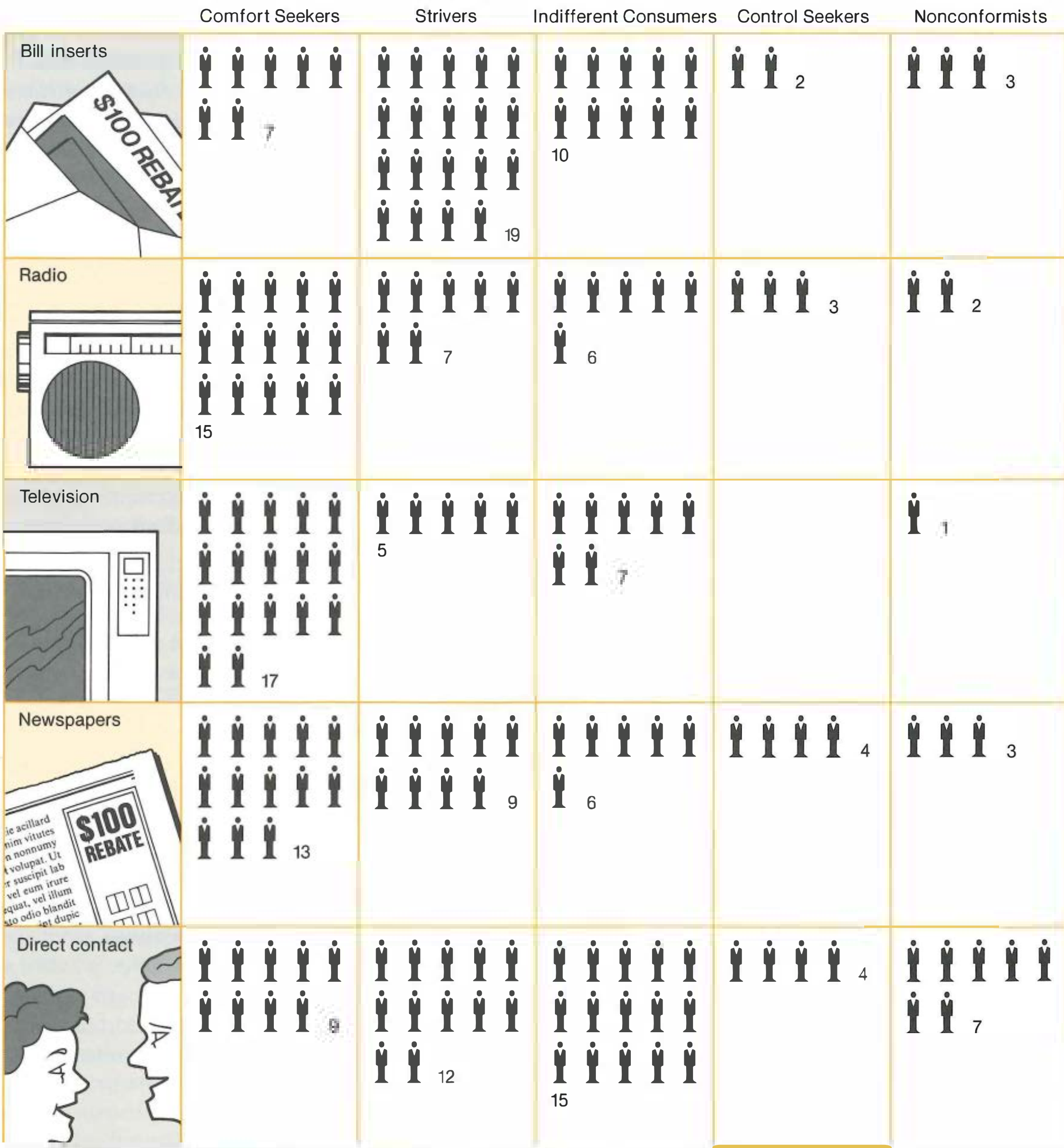
The first step in putting together an effective marketing plan is market segmentation, which specifies target groups based on customer energy needs and preferences. After a basic understanding of the customer segments is formed, an appropriate program design and marketing approach can be chosen for each.

Energy Consumer Type	Load Management/ Conservation Behavior	Best Marketing Medium
Comfort Seeker—Interested in comfort-producing and time-saving appliances. Can afford new technology; money a secondary issue.	Open to load management devices for cautious economizing. Will shop for energy-efficient appliances.	Mass media or consumer publications.
Striver—Upwardly mobile achiever with a high-tech orientation. Interested in appearance, safety, and innovative electronics.	Amenable to load management devices when incentives are offered. Interested in new high-efficiency appliances. Likely to buy service contracts with appliance purchases.	Bill inserts.
Indifferent Consumer—Energy not an important concern in lifestyle. Tends to buy appliances on impulse.	Little interest in load management and conservation but will participate in utility programs if it is easy to do so.	Direct contact.
Control Seeker—Conservative, interested in personal control of his environment.	Highly resistant to load management programs. May implement energy conservation methods on a do-it-yourself basis.	No approach clearly dominant.
Nonconformist—Individualistic, somewhat separate from mainstream society. Generally skeptical of large organizations or businesses.	Unlikely to become involved in load management or conservation activities.	Generally not responsive to marketing.

Reaching the Customer

Getting the attention of customers and sparking their interest in demand-side management programs is a challenge in itself. A number of incentives and communication media have proved effective in different situations, and the thrust of current research is to find which combinations can make large differences in customer acceptance. In this example, where a $100 rebate is being offered for installation of an electric heat pump, the percentage of households that subscribe to the offer will vary substantially among consumer segments and according to the medium used to present it.

Response to Heat Pump Rebate Program
(percent of households)



A third point is the dynamics of household purchase decisions. "We knew households differed from one another, but we've found there are also major differences within households. There may be multiple decision makers with different priorities. Watching the trade-offs they make among themselves is valuable, but you have to be careful when designing and targeting programs. You have to be sure you're reaching the right decision maker. We haven't resolved this one yet."

Other preliminary findings result from interviews at shopping malls. Shoppers responded to a battery of statements in an agree/disagree format: "What I look for in a heating system is even distribution of heat all around the house," or "The best thing about a microwave is the time you can save by using it." Of all the needs that might influence customer choice of appliances or programs, factor analysis of the shoppers' answers identified eight as consistently important: appearance; safety; comfort, convenience, and control; economy and reliability; high-tech features; having the latest equipment; avoidance of hassle; and resistance to utility control.

Fortunately for utility marketing efforts, these factors apply across the range of DSM programs and appliance purchases. "You don't have to meet one set of underlying needs for energy-efficient refrigerators and another set for heat pumps," notes Lewis.

Looking ahead

As work under the customer preference and behavior project continues, several other projects are also feeding into EPRI's research effort in marketing.

Marketing tools from other industries have direct application to utility needs. In a separate project, EPRI is developing a monograph series on marketing techniques and consumer research that will offer utilities a roadmap for establishing and managing cost-effective customer programs.

Another ongoing project will delve into the way that customers weigh capital against operating costs in making appliance purchase decisions. In making the choice between an electric dryer and a gas dryer, for example, how do customers compare the price tag with the dollar cost of running the machine? What time period do they consider? Early results indicate that many older and low-income customers will not buy unless they can recover their capital investment in two years or less.

Market penetration of new technologies is the focus of a recently initiated study. Improved quantitative approaches to estimating market potential will allow utilities to do a better job of promoting new technologies and alternative end-use programs. The project will also consider likely time periods for adoption and diffusion of new technologies among various customer segments.

In sum, EPRI's research in marketing so far has yielded a fund of accumulated wisdom. Most basic is the clear evidence that marketing is effective. It can make the difference between success and failure for utility DSM initiatives.

Further, some marketing approaches work better than others in any given situation. To discover the best strategy in a specific case, utilities must look to their customers. Customer wants and needs define the market.

Following a course charted by this awareness, EPRI's flagship marketing project in customer preference and behavior carries multiple benefits for utilities. It will allow design of better, more-efficient DSM programs; more-precise targeting of those programs; and more cost-effective use of marketing resources. For customers, the benefits include better service, lower rates, and programs tailored to their requirements. This winning combination of utility and customer benefits will inevitably bolster utilities' competitive position in the energy marketplace.

"What we're doing is developing state-of-the-art marketing tools for electric utilities," concludes Lewis. "These tools are designed to be very versatile. Utilities can use them to evaluate a broad range of programs across a great variety of end uses, program design options, and customer groups."

"Market planning and overall utility planning are not separate," Gellings adds. "Quantification of customer behavior and use of the data in utility program planning must become standard as we move into the next decade. If the industry is really going to address the problems of the nineties, we're going to have to focus on the customer." ■

Further reading

"Customer Preference and Behavior." Videotape EM-86-06.

Impact of Demand-Side Management on Future Customer Electric Demand. Special report prepared by T. W. Keelin and C. W. Gellings, August 1986. EPRI EM-4815-SR.

Marketing Demand-Side Programs to Improve Load Factor, Vols. 1–3. Final report for RP2050-11 prepared by Synergic Resources Corp., October 1985. EPRI EA-4267.

Demand-Side Management, Vol. 3. Final report prepared by Battelle, Columbus Laboratories and Synergic Resources Corp., December 1984. EPRI EA/EM-3597.

Electric Utility Conservation Programs: Assessment of Implementation Experience, Vols. 1 and 2. Final report for RP2050-11 prepared by Synergic Resources Corp., July 1984. EPRI EA-3586.

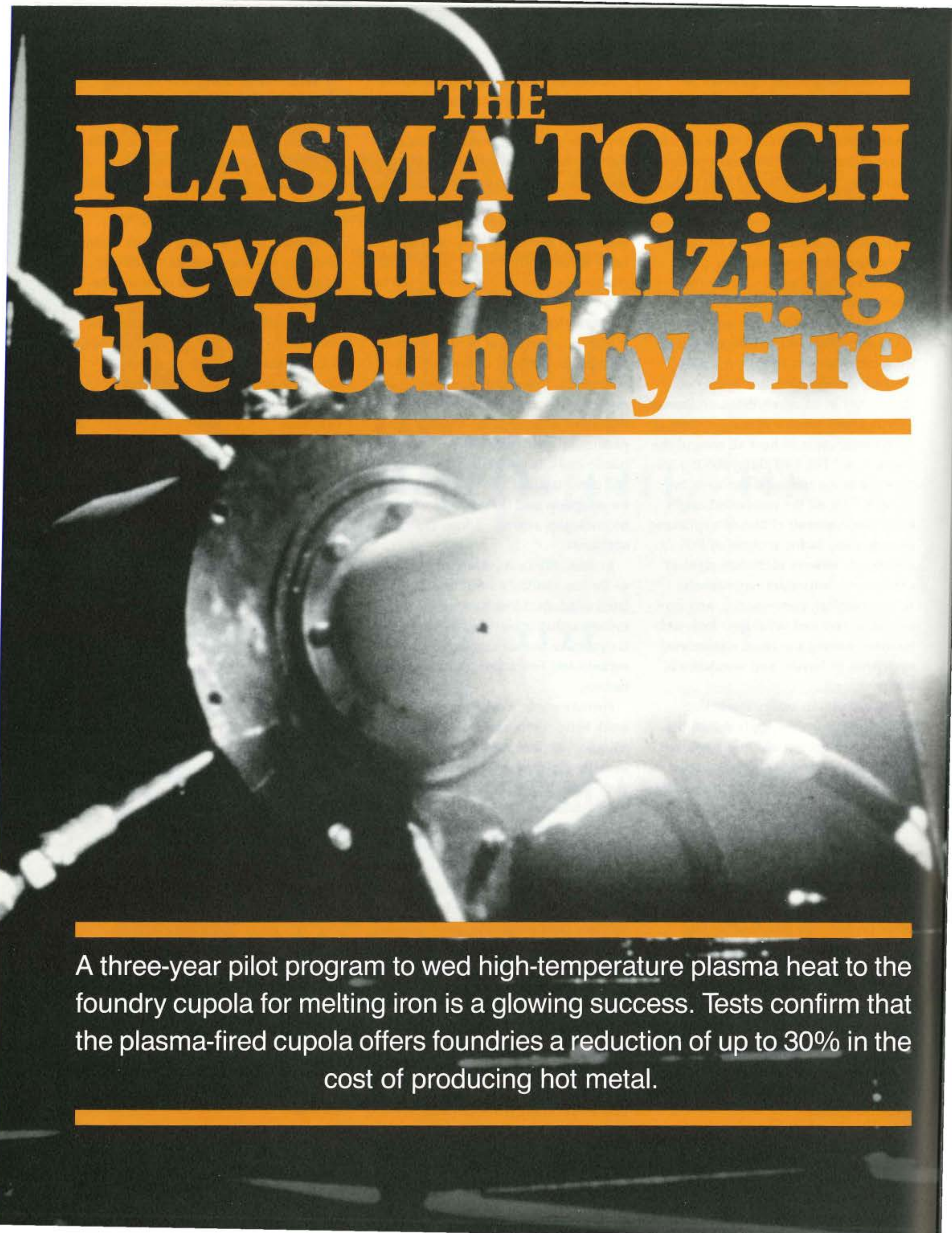
Customer Attitudes and Response to Load Management. Final report prepared by Angel Economic Reports and Heberlein-Baumgartner Research Services, July 1984. EPRI RDS 95.

Issues in Implementing a Load Management Program for Direct Load Control. Final report for RP2050-8 prepared by Energy Management Associates, Inc., March 1983. EPRI EA-2904.

Customer Acceptance of Direct Load Controls: Residential Water Heating and Air Conditioning. Final report prepared by Thomas A. Heberlein and Associates, December 1981. EPRI EA-2152.

This article was written by Mary Wayne, science writer. Technical background information was provided by C. W. Gellings and L. E. Lewis, Energy Management and Utilization Division.

THE PLASMA TORCH Revolutionizing the Foundry Fire



A three-year pilot program to wed high-temperature plasma heat to the foundry cupola for melting iron is a glowing success. Tests confirm that the plasma-fired cupola offers foundries a reduction of up to 30% in the cost of producing hot metal.

Electricity has been gaining steady inroads in the last 10–15 years as an energy form for steelmaking as American producers struggle to maintain position in fiercely competitive domestic and international markets. The electric arc furnace, with an energy efficiency that greatly exceeds that of open-hearth or basic oxygen furnaces and the capability to make liquid metal from 100% scrap, accounted for a third of the 92 million tons of steel produced in the United States in 1984. Its share is forecast to grow to 40% of steel production capacity by 1990.

In other areas of industrial America, electrotechnologies are likewise seen as a key to increasing productivity and reducing costs. EPRI, in collaboration with many of the nation's basic metals and manufacturing industries, has been exploring numerous applications for several years that promise critical economic benefits to industries, as well as new or expanded markets for electric utilities. One of the first of these applications to be the focus of major development effort—wedding the technology of electric-powered, high-temperature plasma to the age-old iron-melting cupola used in foundries—has been confirmed a glowing success.

For foundry operators, the plasma-fired cupola offers a reduction of as much as 30% in the cost of producing hot metal through savings from the use of less-expensive scrap metal charge materials and from reduced energy costs. For utilities, the technology represents potential new demand for power measured in megawatts per cupola and is only one of several uses of plasma heating in materials processing that could come into significant use in the next decade.

Technical results from a three-year, $2.5 million pilot-scale test project—funded by EPRI and Westinghouse Electric Corp., with contributions from Modern Equipment Co. (a Port Washington, Wisconsin, cupola maker) and General Motors Corp.'s Central Foundry Division—were presented in May at the American Foundrymen's Society Casting Congress. Researchers report that plasma-fired cupola technology is ready for commercial use, with the first industrial installations expected to be in place by late next year.

"The success of the cooperative development and test program, coupled with anticipated large-scale commercial applications, represents a breakthrough for plasma-based process heating in this country," notes Alan Karp, project manager in EPRI's Energy Management and Utilization Division. "Researchers have long envisioned large-scale industrial applications of plasma, but these have not previously materialized in the United States. The plasma-fired cupola will finally take this technology off the back burner and constitute an important first step toward fulfilling plasma's considerable commercial potential."

Cupolas in the foundry

The basic techniques of melting iron for foundry casting have been much the same for about 200 years, and the vertical-shaft furnace known as the cupola has been the mainstay melter over most of that time. As recently as the 1950s, there were an estimated 3000 cupolas around the country, but high operating and air pollution control costs, improvements in alternative melting technologies, and cyclical demand depressions in the metals industry have now reduced that number to around 700–800 cupolas. Many low-tonnage cupolas have been replaced with electric induction and electric arc furnaces similar to those used in steelmaking.

"At foundries with high-tonnage and continuous demand, the cupola remains the lowest-cost melting method," says Samuel Carter, a retired production vice president at American Cast Iron Pipe Co. and a consultant to EPRI. Many of the large foundry operations today are owned by automobile and heavy equipment manufacturers and their suppliers for producing gray iron for engine blocks and heads and ductile iron for crankshafts, housings, and the like. Other foundries produce mostly ductile iron for making pressure pipe or various machinery components, as well as alloyed iron for special applications.

Increasingly over the years, cupola operators have tried to make more use of scrap metal in place of expensive pig iron as charge material—the major operating cost item. But some of the lowest-cost forms of scrap could not be used effectively. Steel turnings from lathe operations or cast-iron borings are available in abundance to many foundries, but adding these materials to a conventional cupola can cause operating and metal chemistry problems.

If not first pressed into briquettes (a costly extra step), fine scrap such as borings and turnings may be blown out of the cupola and clog the stack gas cleanup system. Such material with a high ratio of surface area to volume can also result in severe metal loss because of the conventional cupola's highly oxidizing atmosphere, which also causes the oxidation loss of silicon, an important constituent of iron products. Steel turnings, for example, are seldom used today, even in briquette form, because of excessive oxidation losses.

Although a distant second to charge material, the input energy for cupolas is also a major cost factor. Cheaper fuels are used in small amounts, but premium-cost metallurgical-grade coke is predominantly used, in part to minimize problems with sulfur in the flue gas. Despite this, most cupolas have been retrofit with scrubber systems to meet air quality regulations, adding still more to operating costs.

A role for plasma

In 1982 EPRI began a major initiative to encourage new industrial uses of electricity, launching the first of three cooperative R&D centers for electrotechnologies in metals fabrication, metals production, and power electronics. But even as plans for the application research centers were being formulated, interest in electric

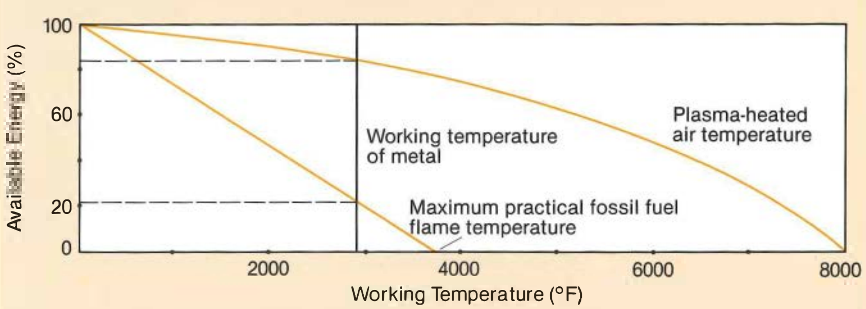
A Plasma Miniprimer

As long ago as the late nineteenth century, it was known that certain gases, including air, take on unique properties when heated to very high temperatures. At about 3600°F (2000°C), gas molecules dissociate into an atomic state. If the temperature is boosted still further to 5400°F (3000°C), the molecules lose some electrons to become ionized. Gas in this hot, ionized state is electrically conducting, can be confined by electromagnetic fields, and has an almost liquidlike viscosity—hence the German term *plasma* to refer to this form of matter, which occurs naturally on the surface of the sun.

Temperatures high enough to transform gas to plasma exceed those normally required for such basic metallurgical processes as iron and steelmaking. Virtually since the dawn of the Iron Age, fossil fuels (mainly coal and coke) and biomass (mostly wood) have provided the heat source for reducing and refining ores to metal.

But plasma's special characteristics, including unrivaled potential enthalpy (energy density), have intrigued scientists and industrial process engineers for decades. Fossil fuel combustion has an upper practical temperature limit of 3600°F (2000°C). Electrically generated plasmas can produce temperatures of 36,000°F (20,000°C) or more.

Such an order-of-magnitude increase in temperature potential opens the door to countless possibilities, including many as yet unconceived uses and opportunities in materials processing. Practical plasma torches were first developed in the 1960s for materials testing to simulate the heat during reentry from space. The long-range implications of understanding and making practical use of the fourth state of matter are truly profound. Ultrahigh-temperature plasma of 50 million °C or more, for example, is a prerequisite for experimental fusion reactors that theoretically could someday produce limitless energy from the deuterium in seawater. □



Advantage of Plasma for High-Temperature Process Heat

One of the advantages of plasmas in process heating is that they contain more available energy for work than do fossil fuel flames at high temperature, which have a practical limit of 3600°F (2000°C). Graph example is for one possible plasma temperature curve. At 2900°F (1600°C), only 20% of the energy in a fossil fuel flame is available for melting metal, but more than 80% of the energy in plasma-heated air is available. Thus, in this example, although electricity for making plasma may cost two to three times as much as fossil fuels, four times as much available energy is contained in the plasma heat than is possible with fossil fuels.

arc plasma heating systems was firmly established. EPRI studies had identified plasma-based heating as one of the few electrotechnologies among those not currently in widespread use that could create significant new demand for electric power in the next 20 years. Analysis indicates that even with no plasma retrofits of existing cupolas, plasma-based materials processing could account for 3600 million kWh of electricity consumption by the year 2000.

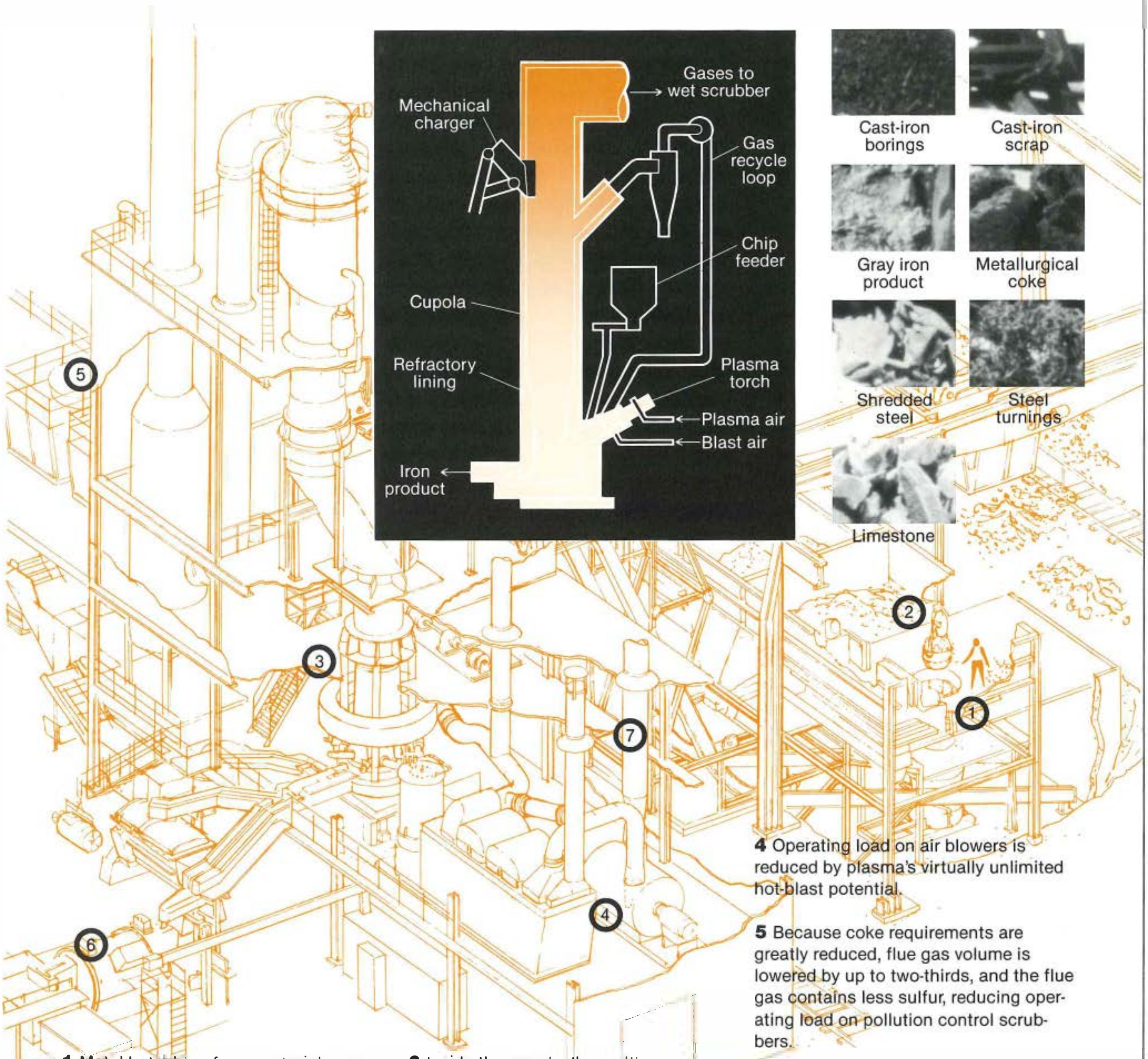
The studies also identified the plasma-fired cupola as a near-term application where EPRI could make a difference. Because plasma systems are such high-power devices, the local cost of electricity (higher than that of fossil fuels in most areas) would be an important consideration in any industry's or company's decision to adopt the technology. In the case of the plasma-fired cupola, however, EPRI's analysis uncovered other benefits that added up to a potential for significant overall cost savings. What was needed was a technologic push in the form of R&D.

In 1983 EPRI helped to bring together the players who would be needed to fund, build, and demonstrate a pilot-scale plasma-fired cupola. Westinghouse supplied one of its 2-MW MARC-11 plasma torches, a test site (the company's Waltz Mill plasma center near Pittsburgh), and its extensive experience with plasma systems. Modern Equipment provided the cupola (a 2.5-t/h water-cooled, refractory-lined design) and related expertise. General Motors' Central Foundry Division supplied much of the nearly 200 t of metal melted in the test phase, including a large proportion of scrap chips and borings, as well as technical and analytic support.

The Westinghouse plasma torch is a surprisingly simple, commercially available device similar to units offered by other firms active in plasma systems development. A thyristor-controlled high-amperage dc power supply maintains the electric arc between two copper sleeve-type, water-cooled electrodes.

Plasma Retrofit Offers Benefits Throughout the Foundry

Retrofitting a cupola with plasma-firing can improve operation in many ways. Installed at the tuyere level where hot blast air is normally injected to aid in combustion, plasma torches yield improved melt and off-gas chemistries, as well as reduce the operating load on flue gas scrubbers and air blowers.



1 Metal batching of raw materials can include low-cost scrap iron and steel in loose, unbriquetted form.

2 Nonmetallic batching can use smaller-size coke and less of it, or it can substitute coal because of the noncombustion high-temperature plasma.

3 Inside the cupola, the melting process is largely decoupled from the factors governing product chemistry. In addition, less blast air is required, reducing cupola backpressure. The less-oxidizing atmosphere created by plasma heat also permits the reduction of silicon from ordinary sand.

4 Operating load on air blowers is reduced by plasma's virtually unlimited hot-blast potential.

5 Because coke requirements are greatly reduced, flue gas volume is lowered by up to two-thirds, and the flue gas contains less sulfur, reducing operating load on pollution control scrubbers.

6 Productivity of existing facilities for handling hot metal is maximized with plasma firing.

7 Automatic controls, including safety interlocks, are built in with plasma torch firing.

Power is taken from the local grid at 4160 V and rectified to ±1000 Vdc. An induced magnetic field rotates the arc around the diameter of the electrodes to prevent excessive wear at any one point.

Air, nitrogen, or (if desired) another gas is passed through the arc, where it is ionized and almost instantly heated to temperatures as high as 10,000°F (5538°C). Westinghouse says the efficiency of the torch in converting electric energy to thermal energy is 85–90%.

The plasma torch is installed in the tuyere zone at the bottom of the cupola, where air and sometimes oxygen are normally injected to support coke combustion. Additional blast air is provided at the torch-cupola junction for thermal dilution and protection of the cupola's refractory material.

Iron and scrap charge in 55-gal drums is mechanically fed through a door at the top of the pilot cupola. Liquid iron and slag are continuously tapped below the tuyere level, using a conventional dam-and-skimmer type of spout. Stack gas can be recycled through the cupola for added flexibility and control over gas composition. The test unit was fully instrumented for data acquisition and gas chemistry analysis.

On the test campaign trail

Commissioned in late 1984, the pilot plant conducted 20 heats during 1985 and early 1986. The typical heat lasted 10–12 h from startup to shutdown and included 4–6 h of actual iron production. The heat started with a bed of preignited coke, the charge drums were emptied into the top, operators switched on the power to fire the plasma torch, and iron began to melt. Samples were collected every 10 min.

"Each heat was designed to test a different type of operation with respect to parameters including charge mix, recycle gas flow rates, sand injection rates for silicon production, and plasma torch power levels," explains Shyam Dighe, project manager at the Westinghouse Waste Technology Services Division,

A Plasma Solution for Chemical Wastes

One of the promising uses to which plasma heat may soon be put is destroying some of the country's growing inventory of toxic and hazardous chemical wastes. Under contract to the New York State Department of Environmental Conservation (NYSDEC), Ontario-based Pyrolysis Systems, Inc., has constructed and is testing a mobile chemical waste destruction system that promises near-total rendering of typical liquid wastes. Destruction may be up to 10,000 times more effective than that of most high-temperature incinerators. A prototype unit has successfully completed field tests in Canada and has been delivered to the Love Canal site at Niagara Falls, New York, where it is expected to begin helping in the cleanup by next year.

The system, contained in a tractor-trailer, includes an off-the-shelf Westinghouse plasma torch fitted to a reactor chamber. Liquid wastes are pumped in at the junction, where plasma heat pyrolyzes wastes at a rate of 1 gal/min (3.8 L/min) to form basic molecules of hydrogen and carbon monoxide, as well as carbon particulate. A scrubber neutralizes the acid off-gas and removes the bulk of the carbon particulate before the hydrogen and carbon monoxide that remain are flared outside the trailer.

Officials of EPA and NYSDEC, which funded the $1 million unit, say extensive tests so far indicate destruction efficiencies greater than 99.99999%. Such extreme effectiveness is required for some complex and toxic organic compounds, including dioxins. Authorities report excellent results destroying polychlorinated biphenyls (PCBs), a common utility industry waste, as well as carbon tetrachloride.

"The technology has a very high potential for destroying liquid wastes," says Chun Cheng Lee, a program manager at EPA's Industrial Environmental Research Laboratory in Cincinnati, Ohio. "It destroys PCBs very well, and if it works as well with Love Canal liquids, it can destroy many types of chemicals."

Nicholas Kolak, supervisor of special projects in NYSDEC's division of solid and hazardous waste, agrees the outlook is favorable. "We're very optimistic and enthusiastic about this technology. There is still a long way to go, but we are test-burning various materials and expect to try a 20-day continuous burn sometime next year. Very soon, we hope to begin trial burns on some of the 20,000 gal (75,700 L) of liquid organic wastes stored at Love Canal." Kolak says waste processing activities at the Love Canal Leachate Treatment Facility are generating an additional 200–300 gal/mo (757–1135 L/mo), but that all this material conceivably could be destroyed in a matter of months if the plasma unit is operated at full bore.

Meantime, a larger model of the unit—one with capacity to destroy 3 gal/min (11.4 L/min)—was completed this summer for use in Canada, possibly this year. "We think there's a pretty good-size market on both sides of the border," says Steven Vorndran, president of Westinghouse Plasma Systems, a joint venture between the electric equipment maker and Pyrolysis Systems, Inc. Eventually, the company envisions many such mobile systems in use around the country that could "roll in, do our thing at the site, and leave." □

which includes the company's plasma technology program.

The plasma torch was operated over a wide range of power levels, most of the time at 600–1200 kW. The power and, with only a 3–4-min lag, the melt temperature can be adjusted simply by changing the arc current. Conventional procedure involves painstakingly fine-tuning the air volume and coke-to-metal ratios and entails longer response time. "Now we have only to turn electric dials, rather than adjust valves and flow rates, to control the melt," says Dighe. "For every 25-kW increase in torch power, a 5°F/min (2.7°C/min) rise of molten iron temperature was observed."

Adds Carter, who helped pioneer several developments in large industrial cupolas, "The plasma-fired superheat produces a thermal boost in the melting zone and combustion process greater than any I have witnessed." The torch can easily double the blast temperature of 1200–1800°F (650–980°C) obtained in conventional hot-blast cupolas.

"These dramatically increased temperatures favor the reduction of silicon oxide, rather than the oxidation of silicon, thereby reducing silicon losses and making possible the production of silicon from sand," explains Carter. In conventional cupolas, silicon makeup is typically obtained by the addition of expensive ferrosilicon.

Because most of the heat is introduced by the small stream of plasma gas rather than through the combustion of coke with its associate generation of large volumes of combustion gases, gas flows through the plasma cupola are only about one-third of those required with all-coke firing. This feature results in a dramatically lower gas velocity and back-pressure in the cupola, which make it possible to charge very fine material through the door at the top. In several test heats, up to 75% of the metal charge was in the form of loose cast-iron borings. The melt yield of the charge was as high as 98.5%, consistent with the high yields obtained in nearly all the heats.

Increases of better than 50% were indicated by test data on the effect of torch power on melt rate. In one heat, the torch was operated at three power levels, corresponding to equivalent blast temperatures of 1875, 2275, and 2675°F (1025, 1245, and 1470°C), with observed melt rates of 1.8, 2.7, and 2.9 t/h, respectively.

Dramatic reductions in coke requirements were also confirmed in the cupola tests, with metal-to-coke ratios ranging between 8:1 and 70:1—as much as a 10-fold increase over current practice. A ratio of 42:1 over a long heat was clearly established.

In summarizing these test results, EPRI's Karp observes, "Plasma firing for

Case Studies of Plasma-Fired Cupola Economic Benefits

Following successful pilot-scale tests of the plasma-fired cupola, EPRI sponsored detailed analysis by cupola-maker Modern Equipment Co. of 11 different foundry operations for potential benefits of retrofitting plasma heating technology. The case studies included single as well as multiple cupola operations and covered a range of furnace types and melt rates. In most cases, the greatest projected savings came from the ability to use cheaper charge materials, but in all cases there were at least some and, in a few cases, significant additional savings in energy costs despite the higher cost per Btu of electricity compared with that of fossil fuels.

		Operating Cost Savings With Plasma ($/t)		
Foundry Type	**Melt Rate** (t/h)	**Charge Materials**	**Energy**	**Simple Payback** (yr)
Hot-blast cupola	35	29.00	3.30	1.5
Hot-blast cupola	35	28.40	3.40	1.6
Hot-blast cupola	40	24.20	7.70	1.6
Hot-blast cupola	30	15.30	1.25	4.2
Hot-blast cupola	15	34.40	1.65	1.6
Hot-blast cupola	45	28.00	5.70	1.4
Induction melter	40	20.70	14.20	2.3
Arc furnace	65	28.00	30.00	1.3
Hot-blast cupola	40	17.90	1.50	1.9
Induction melter	5	23.20	9.00	8.4
Hot-blast cupola	45	49.00	7.20	0.6

foundry melting is an innovation that embodies much more than just the substitution of electric Btu for coke. With the plasma-fired cupola, we have largely decoupled the melting process from the factors that govern product chemistry. In so doing, we are able to independently alter and optimize both."

Dighe of Westinghouse agrees. "We now have a cupola that behaves radically differently—it can accept raw materials that were previously unusable. We took a well-established technology, coupled it with another high technology—the plasma torch—and found that when you put them together, the whole is greater than the sum of the parts.

"Moreover, the project has shown that plasma firing can yield benefits far in excess of the increased cost of electricity per Btu relative to fossil fuels. And because plasma firing permits the use of cheaper coke or coal, energy costs per ton of melt are often lower than with a conventional cupola," Dighe adds.

The retrofit decision

Applying the results from the pilot-plant tests to the actual operating conditions at over a dozen foundries indicates a net cost saving from plasma firing of \$20–\$60/t of melt. Eighty percent of that saving is estimated to come from reduced metal costs through the use of cheaper forms of scrap, and 20% is attributed to lower total energy costs and reduced silicon loss.

Capital costs of plasma torch systems are about \$270/kW of capacity. The additional costs of installation, controls, cupola modifications, and building and site alterations may increase the figure by a factor of 2.3–2.7, giving a total retrofit cost estimate of \$620–\$730/kW.

But depending on the foundry production rate, local electricity rates, and the availability of low-cost scrap, investment payback could come in one to three years. "Payback periods of less than a year have been projected in some cases," says Karp. "Moreover, the plasma-fired cupola's ability to handle a much wider

Conventional cupola at the Rockford, Illinois, foundry of Gunite Division, Kelsey-Hayes Co. (Photo by Ronald William May.)

range of scrap materials, alloy sources, and carbon sources ensures that good economics can be maintained as prices in the marketplace change. Once plasma firing is installed, the foundry operator has almost total freedom to minimize costs by changing the charge mix or altering the electricity–fossil fuel ratio," he adds.

Although large foundries may be in a better position to absorb the capital cost, EPRI-sponsored studies indicate that plasma firing can be economically attractive over a wide range of melt rates. Adds F. T. Kaiser, executive vice president of Modern Equipment Co., "Our studies indicate that a plasma torch–equipped cupola for melt rates in the 5-t/h range may be economically viable. At this relatively low melt rate, it is possible that smaller foundries may be able to find sufficient supplies of loose steel turnings or similar materials of acceptable chemistry to considerably reduce their melting costs."

According to Karp, "An increasing number of utilities are actively pursuing possible applications with their local foundry customers. Plasma heating represents an electrotechnology where utilities can help tilt the balance in favor of innovative modernization." These utilities include Alabama Power Co.; Cleveland Electric Illuminating Co.; Commonwealth Edison Co.; Consumers Power, Inc.; Georgia Power Co.; Illinois Power Co.; Pacific Gas and Electric Co.; Pennsylvania Power and Light Co.; Tennessee Valley Authority; and Toledo Edison Co. Adds Dighe, "The U.S. foundry industry now has a tool with which to compete against foreign producers."

New horizons

The plasma-fired cupola, available from Westinghouse under an exclusive EPRI license, is now a commercial reality. But researchers are quick to point out that does not mean the end of R&D. EPRI and Westinghouse have been joined by six large foundry operators and Modern Equipment in sponsoring continuing evaluations at the pilot plant to further investigate process parameter improvements, different types of charge materials, other fuel substitutions, and such foundry operations as ductile and malleable iron production.

"We also want to try some blue-sky kind of things," says Karp. "We have not yet seen the full potential of plasma firing." Also providing technical and financial support for the follow-on studies are American Cast Iron Pipe Co., Ford Motor Co., Intermet Corp., the Gunite Division of Kelsey-Hayes Co., Stockham Valves and Fittings Co., and Tyler Pipe Industries.

Meantime, EPRI's industrial electrotechnology program is preparing to explore other applications of plasma heating. Several American and European metals producers have developed or are working on plasma applications for steel melting; smelting reduction; direct iron ore reduction; and recovery of zinc, lead, chromium, and other metals from electric arc steel furnace baghouse dusts. Prominent among them are Plasma Energy Corp., Raleigh, North Carolina; Retech Inc., Ukiah, California; Austria's Voest-Alpine; France's Aérospatiale; Japan's Nippon Kokan Steel; Sweden's SKF Steel Engineering Ab; and West Germany's Krupp.

I. Leslie Harry, EPRI program manager for industrial electrification, says the Institute hopes to have a research project in place by the end of this year to test at pilot scale the recovery and recycling of zinc from arc furnace steel dusts.

Steel plants produce an estimated half a million tons a year of very fine dust that is now classified by the Environmental Protection Agency as a hazardous waste. A recent analysis from the Center for Metals Production by Bethlehem Steel Corp.'s research department found that for those dusts containing more than 20% zinc, on-site plasma-based processing could be an attractive recovery option compared with chemical treatment as waste or direct recycle to an arc furnace.

"It may be that the waste area is a natural for plasma systems because of the very high temperature and fast reaction time," notes Harry. "Considering the variety of metallic and other hazardous wastes around the country waiting for a disposal solution, the market for plasma systems is ready-made."

Fire of the future

As with the advent of fossil fuels in centuries past, electric arc plasma opens a new dimension in materials processing of which the world may have only begun to glimpse the edges. Paradoxically, among its first practical industrial applications may be to help revive the depressed economics of one of the oldest uses of fossil fuel combustion—the making and melting of metal.

EPRI's success with the plasma-fired cupola may herald similar technologic innovation in other fields of metals production. As various basic American industries search for sustained vitality in the midst of volatile global competition, the odds are great that plasma heat will find a number of important niches in the years to come. ■

Further reading

S. V. Dighe et al. "Plasma-Fired Cupola: An Innovation in Iron Foundry Melting." AFS Transaction Paper, 1986. Presented at the 90th Casting Congress, May 11–15, 1986, Minneapolis, Minnesota.

S. F. Carter and F. T. Kaiser. "The Plasma-Fired Cupola—An Operator's Appraisal and Economic Projections." AFS Transaction Paper, 1986. Presented at the 90th Casting Congress, May 11–15, 1986, Minneapolis, Minnesota.

H. J. Heine. "Plasma-Fired Cupola Promises Melting Economies." *Foundry Management & Technology*, Vol. 114, No. 3 (March 1986), pp. 28–30.

Plasma Processes for Metals Production. Prepared by Richard Fruehan, Center for Iron and Steelmaking Research, Carnegie-Mellon University, for the Center for Metals Production, October 1985. CMP 85-3.

"Plasma-Fired Cupola: Innovative Foundry Melting." Videotape for RP1275, September 1985. Tech Tape EM85-02; length. 12:00.

Electric Arc Furnace Dust—Disposal, Recycle, and Recovery. Prepared by Research Department, Bethlehem Steel Corp., for the Center for Metals Production, May 1985. CMP 85-2.

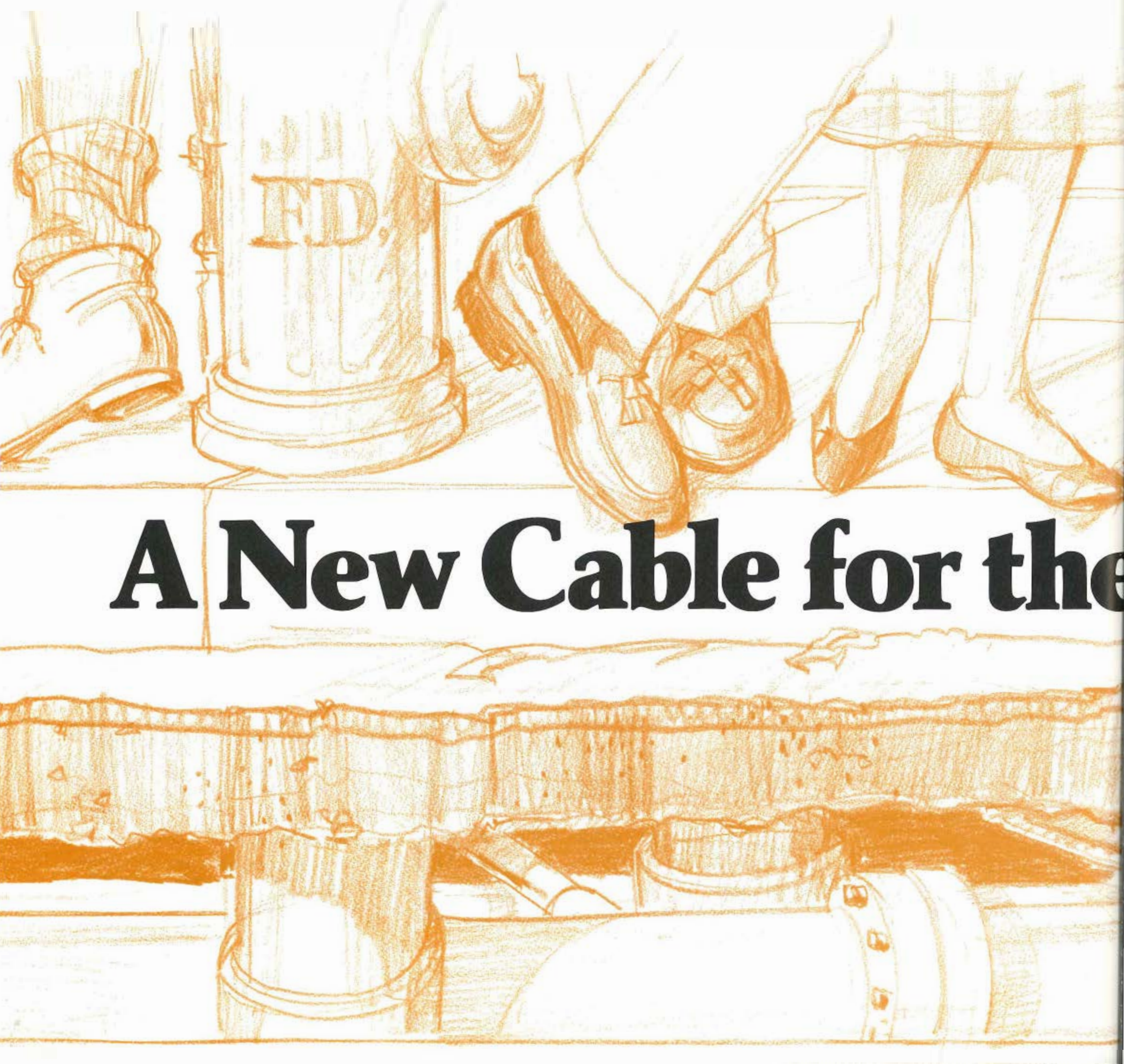
J. J. Dwyer, Jr. "The Promise of Plasma." *33 Metal Producing*, Vol. 22, No. 2 (February 1984), pp. 33–41.

Plasma Processing for Materials Production. Final report for RP1275-9, prepared by Westinghouse Electric Corp., December 1982. EPRI EM-2771.

This article was written by Taylor Moore. Technical background information was provided by Alan Karp and I. Leslie Harry, Energy Management and Utilization Division.

Close quarters are an urban reality that drives transmission systems underground—an expensive proposition. A new, more efficient insulating tape made of plastic laminate will allow utilities to use smaller pipe-type cables for new installations or push more power through existing systems by recabling.

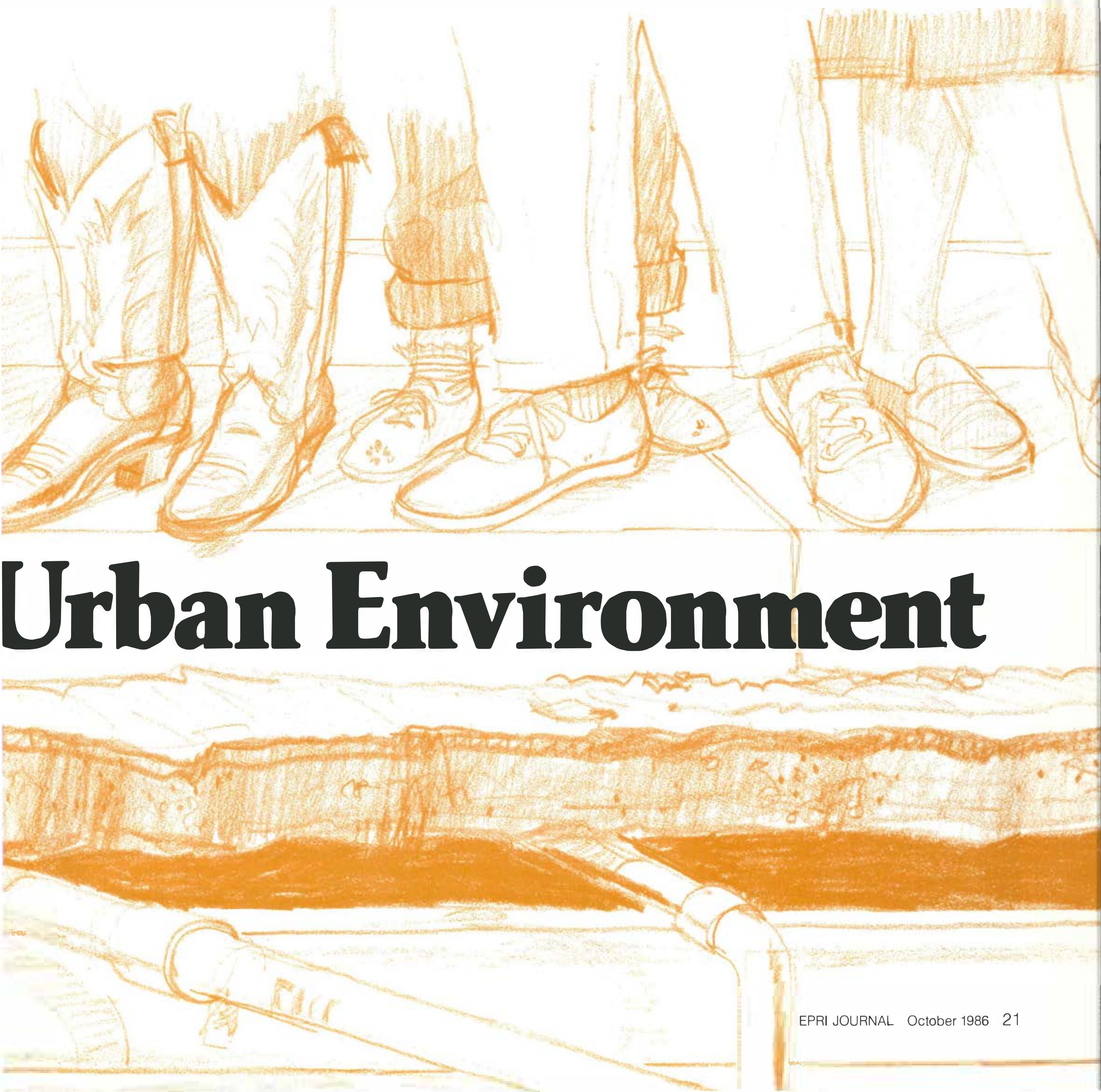
A New Cable for the



Underground power delivery is a fact of life. Electric utilities frequently use buried cable for distribution systems into neighborhoods, the higher cost unquestioned because esthetic standards have even higher value.

Sometimes it also makes sense to place transmission systems underground—systems rated 69 kV and higher, which bring power from generating plants into distribution centers. This becomes a real likelihood when power must traverse well-established urban areas that are building outward and upward at great expense and density. Because overhead lines require more space than underground cable, the foot-for-foot economy of an overhead transmission system can be overwhelmed by the cost of right-of-way needed.

Air being a relatively poor insulator, the bare conductors of an overhead ac circuit must be strung farther apart from each other at higher voltages. But conductors can be close together in a cable. Wrapped insulation makes this possible, so buried transmission cable—perhaps



Urban Environment

10 in (25.4 cm) in diameter for all three conductors—is the economic choice. Underground transmission is intrinsically expensive, but in some circumstances, paradoxically, overhead transmission is the option that goes out of sight.

For 60 years utilities have gone underground with transmission cables wrapped in oil-impregnated paper tape insulation. (Low-voltage distribution cables of this type date from 1895.) For 50 years most such cables have been encased in high-pressure, oil-filled (HPOF) pipe, composing what are known as pipe-type cable systems. The oil acts mainly as a dielectric and sometimes as a coolant, permitting an increased power rating for the circuit.

Stepped-up properties

Over the years, improvements in paper and oil have yielded incrementally higher voltage capability and lower dielectric losses. Now, however, there is promise of a major advance in HPOF technology: a new insulating tape with markedly better dielectric properties. Developed largely under EPRI auspices during the past 14 years, it is a sandwich of polypropylene film between two layers of traditional cellulose paper.

The significance of so-called PPP insulation is that its properties should lead directly to a number of savings in cable material, installation, and operating costs.

Most important, the dielectric strength of PPP tape is 25–30% greater than that of paper alone. This means reduced insulation thickness for a given cable voltage. The implications are smaller cable and pipe diameters for that voltage or a higher cable voltage for the same diameter. The latter is appealing as a means to upgrade existing HPOF systems by as much as two voltage levels, say, from 138 kV to 345 kV.

A close second in importance for cable wrapped with PPP laminate is its reduced dielectric loss, less than one-third that of paper-wrapped cable. For a 345-kV cable tested at EPRI's Waltz Mill, Pennsylvania, facility, the loss was 12.4 kW/mi (7.7 kW/km), and for a paper-wrapped equivalent, 47.0 kW/mi (29.2 kW/km). This characteristic of PPP tape produces a lifelong operating saving because of lower losses whenever the cable is energized.

A third improved electrical characteristic is dielectric constant—as low as 2.65 for PPP laminate in comparison with 3.5 or 3.6 for today's paper. This suggests lower charging current as well, but any such improvement is for the most part nullified by the reduced diameter of PPP-insulated cable.

Material and installation economies derive from the smaller diameter of PPP cable because it requires a smaller pipe and therefore a smaller volume of dielectric liquid. Further, a greater continuous length can be wound on a reel of shippable weight and diameter. Installation pull length is thus increased, meaning more widely spaced manholes and fewer as well as smaller field splices to be made between cable sections.

The single component behind all these advantages is a laminate of polypropylene and cellulose paper with higher dielectric strength than paper alone and less than one-third the losses of paper alone. Why not produce the tape entirely of polypropylene?

The answer is that paper preserves necessary mechanical stability. Purely plastic tape stretches easily, and controlling its tension is therefore difficult. But tension, in turn, influences the precision with which tape can be wrapped on a conductor. Turns of tape must not overlap, for example; a small but uniform longitudinal gap must be maintained so that the wrapped conductor can bend and the tape slide slightly without wrinkling the tape. This is the limiting factor on cable flexure because deformation of the tape reduces its dielectric performance.

Additional layers of tape cover such gaps, of course, but create their own. The offset gaps and paper layers form a zigzag path for dielectric oil, which cannot soak through the polypropylene but must make its way between all tape layers so that the wall becomes thoroughly oil-impregnated.

If a suitably inelastic polypropylene can be developed, an all-film tape may be practical. Already, embossing its surface is seen as a way to create annular space for a layer or film of dielectric liquid.

Laminated as it is, PPP tape is expensive on a unit basis. Its cost-effectiveness will come from the performance efficiencies and material economies detailed earlier. Even at $2.50 a pound, strictly an estimate for production quantities at some future time, according to EPRI Program Manager Ralph Samm, the PPP tape would be three times today's $0.85 per pound cost of paper tape. Early experimental quantities of PPP tape from abroad have cost as much as $9.00 a pound, and $5.00 is a current estimate for domestically produced pilot quantities.

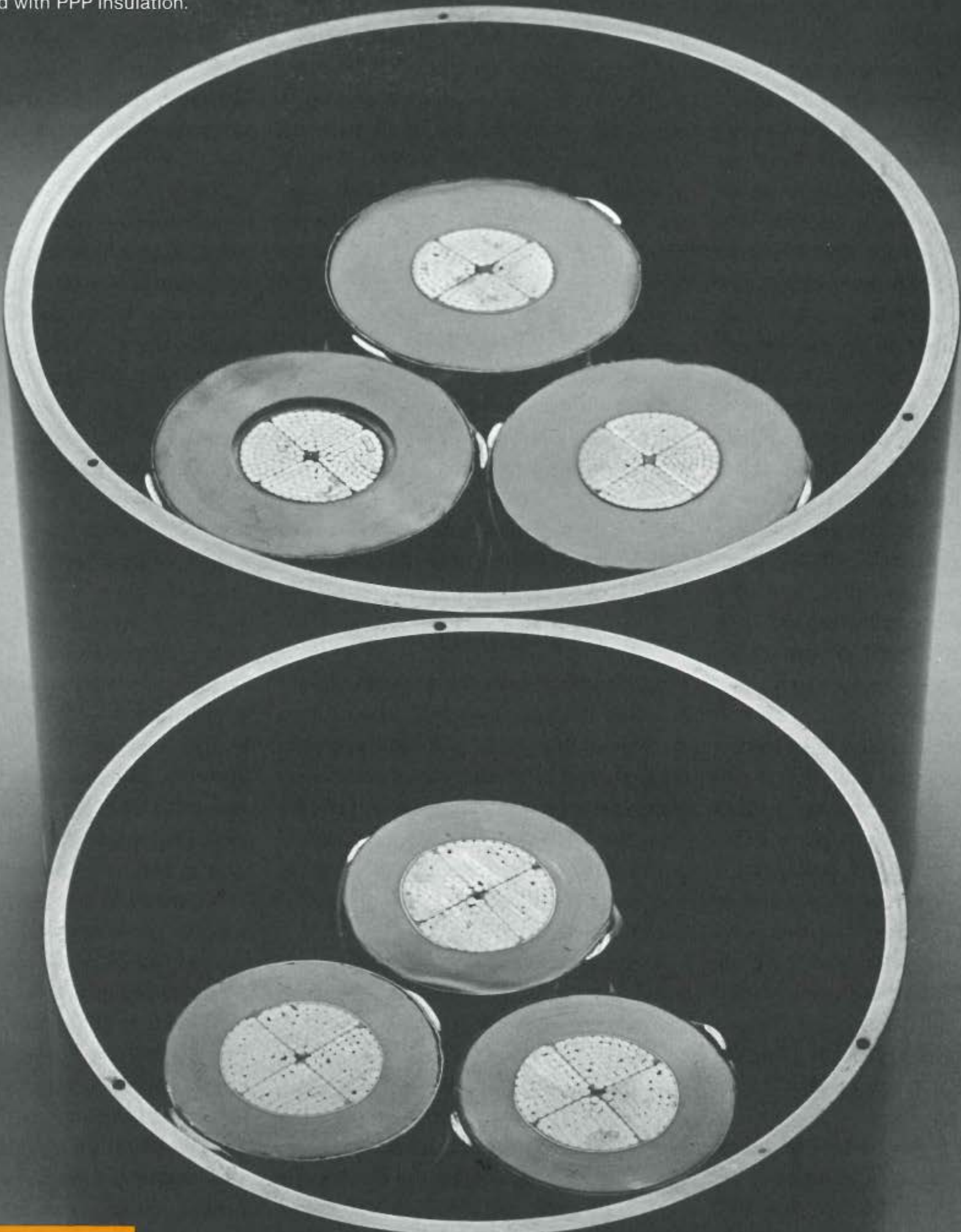
Three utility projects

The watershed year for PPP-insulated cable should be 1988, when feeder circuits will be in commercial service for Boston Edison Co., Consolidated Edison Co. of New York, Inc., and New Jersey's Public Service Electric and Gas Co. (PSE&G). EPRI will provide some funding or in-kind assistance in testing, monitoring, and advisory services to the host utilities of all three installations.

Aptly enough, the three cable projects are in mid- and north-Atlantic coastal cities, in states that already have more than a third of all U.S. underground transmission capacity. The three utilities, all members of EPRI, have carefully followed the R&D through the years; their representatives now serve as advisers on EPRI's industry task force for underground transmission. Aptly also, the three projects are different in ways that should prove PPP-insulated cable in several settings and thereby encourage utilities to adopt it confidently and soon.

Boston Edison's $22.5 million project involves a paired 345-kV circuit, a 6.2-mi (10-km) tie with New England Power Co. that will augment regional delivery capability for power generated in upper New

The lesser thickness of PPP insulation is evident in this side-by-side comparison of PPP-wrapped and paper-wrapped conductors making up 345-kV cables. The 8- and 10-in pipe diameters illustrate the savings in cable materials, dimensions, and cost that are expected with PPP insulation.



PPP-Cable Savings

Operating savings give PPP cable its real economic edge—the result of smaller dielectric loss whenever the cable is energized. This comparison is based on 345-kV cable, with PPP costing $5.00 a pound.

England and Canada. The circuit will use 2000-kcmil conductors, with 600-mil wall thickness, in 8-in pipe. Pull lengths will average 3000 ft (0.9 km). Polybutene will be the dielectric liquid.

For some time Edward Geary of Boston Edison has served as an adviser to EPRI's program of cable R&D, and the utility's PPP choice stemmed in part from his monitoring of that particular development. In fact, the utility's decision was nearly simultaneous with EPRI's solicitation of proposals from prospective host utilities. Boston Edison is therefore looking to EPRI primarily as an adviser and for confirmation of the cable manufacturer's type tests on the new cable.

Con Edison's demonstration is a $4.6 million retrofit—10,000 ft (3 km) of 36-yr-old 69-kV feeder in New York City to be upgraded to 138 kV. The new conductors will be 500 kcmil each, with a 270-mil wall, pulled into 5- and 8-in pipe. The existing 69-kV cable conductors are 1250, 1000, and 600 kcmil, with 285-mil walls.

The project is seen as an experiment by Con Edison's Henry Chu and his colleagues in the transmission engineering and R&D departments, and the circuit chosen is thoroughly backed up by other feeder capacity. Con Edison plans to install the new cable in five pulls, but it may be possible to skip manholes and go for longer continuous sections; this point is still under consideration with the cable supplier. Two years of monitoring should yield the service history Con Edison needs for a policy decision on other 69-kV cable circuits that are candidates for upgrading.

Con Edison will pay 63% of the demonstration project cost; funding from the Empire State Electric Energy Research Corp. covers another 30%, and EPRI is contributing 7%.

PSE&G is scheduling a $4.5 million installation, a 230-kV circuit 14,400 ft (4.4 km) long, one of six that will eventually feed an extensive development along an 11-mi (17.7-km) stretch of Hudson River shoreline in New Jersey. The PPP-insulated cable will use a 1750-kcmil conductor having a 450-mil wall, encased in an 8-in pipe. The paper-insulated cables for five companion circuits will use 2000-kcmil conductor with a 630-mil wall.

All six circuits will be closely monitored to compare installation and operating characteristics under similar circumstances. Four pulls of PPP cable are planned, averaging 3600 ft (1.1 km) each; the longest (through a railroad tunnel) will be 4500 ft (1.4 km). Pulling tension behavior of this section will be checked against that of other long sections (4800 and 5500 ft; 1.5 and 1.7 km) planned for the project.

According to John Jurcisin, the utility's project engineer, the PPP-wrapped cable will be subject to early and significant loading, relative to the other circuits. EPRI demonstration funds cover about 11% of the PPP circuit cost; the remainder is being paid by PSE&G.

Sixteen-year development

Pipe installation on the projects should begin in the spring of 1987. The utilities are scheduling cable pulls beginning in August, and all three utilities plan to energize their new cables at the end of 1987 or at the latest by mid 1988. Methodical performance monitoring then gets under way, which will be the climax of an R&D effort that began 16 years earlier.

Transmission voltages were on an upward trend in 1972, and the particular incentive for cable improvement was to limit dielectric losses. They increase as the square of the operating voltage in a paper-insulated cable, becoming prohibitively high at ratings above 500 kV.

The initial step was by the Electric Research Council, a utility industry group of the 1960s that sponsored selective R&D projects and eventually recommended the establishment of EPRI. In the same month that EPRI was incorporated (April 1972), coincidentally, ERC contracted with Phelps Dodge Cable & Wire Co. for a feasibility study of 765-kV HPOF cable.

EPRI later took over management of that effort, and the federal government (DOE and its predecessors) became a cosponsor. Cablec Corp. was the corporate successor to Phelps Dodge, and its work yielded a prototype that underwent lengthy testing at EPRI's Waltz Mill Underground Cable Test Facility in Pennsylvania, exhibiting dielectric losses only one-third those of paper-wrapped cable.

But by the 1980s it was apparent that higher-voltage cables were not the real need. Transmission trends had leveled, but utility costs of every kind—money, materials, labor—were still escalating sharply. EPRI revised the project focus downward, to a goal of optimized cable designs for 345 kV and below. Accordingly, a 345-kV prototype is now commencing its type tests at Waltz Mill.

Cablec, EPRI's research contractor, is so far the only licensed PPP cable fabricator in the United States. Other companies are considering the product, however, and EPRI seeks licensees for the technology it sponsored.

Cable joints (or splices) have not been overlooked during the development. A study done for EPRI by Underground Systems, Inc., established that the length and girth of cable joints can be far less with PPP insulation, with corollary savings in both materials and field labor.

For example, the length of the joint in a 345-kV cable can be reduced from 105 in (267 cm) to 54 in (137 cm), and the joint diameter (for one phase) from 5.7 in (14.5 cm) to 4.2 in (10.5 cm). A practical sidelight is that the thermal capability of a PPP-insulated joint is nearly that of the rest of the cable; the joint is no longer the limiting factor on cable rating.

Dielectric liquids have also been investigated during the PPP development. Two synthetics in commercial use are proving to be suitable with PPP tape. Polybutene was used for EPRI's 765-kV prototype testing at Waltz Mill. It is being used there for the 345-kV prototype also, but alkyl benzene was used successfully in laboratory tests of that cable. Mineral oil, formerly the industry's most com-

The First Applications

Three utility projects to be carried out in 1987 will provide operating experience for PPP-insulated cables of different voltages under different operating conditions.

	Boston Edison	Con Edison	PSE&G
Voltage (kV)	345	138	230
Condition	New	Upgrade	New
Length (km)	10	3	4.4
Conductor (kcmil)	2000	500	1750
Wall thickness (mil)	600	270	450
Pipe diameter (in)	8	5 and 8	8
Dielectric liquid	Polybutene	Polybutene	Polybutene

monly used liquid, is not compatible, however, other than in residual quantities. The Con Edison upgrade in New York, for example, will involve emptying the pipe of mineral oil and cleaning it before the new PPP-wrapped conductors and dielectric liquid go in.

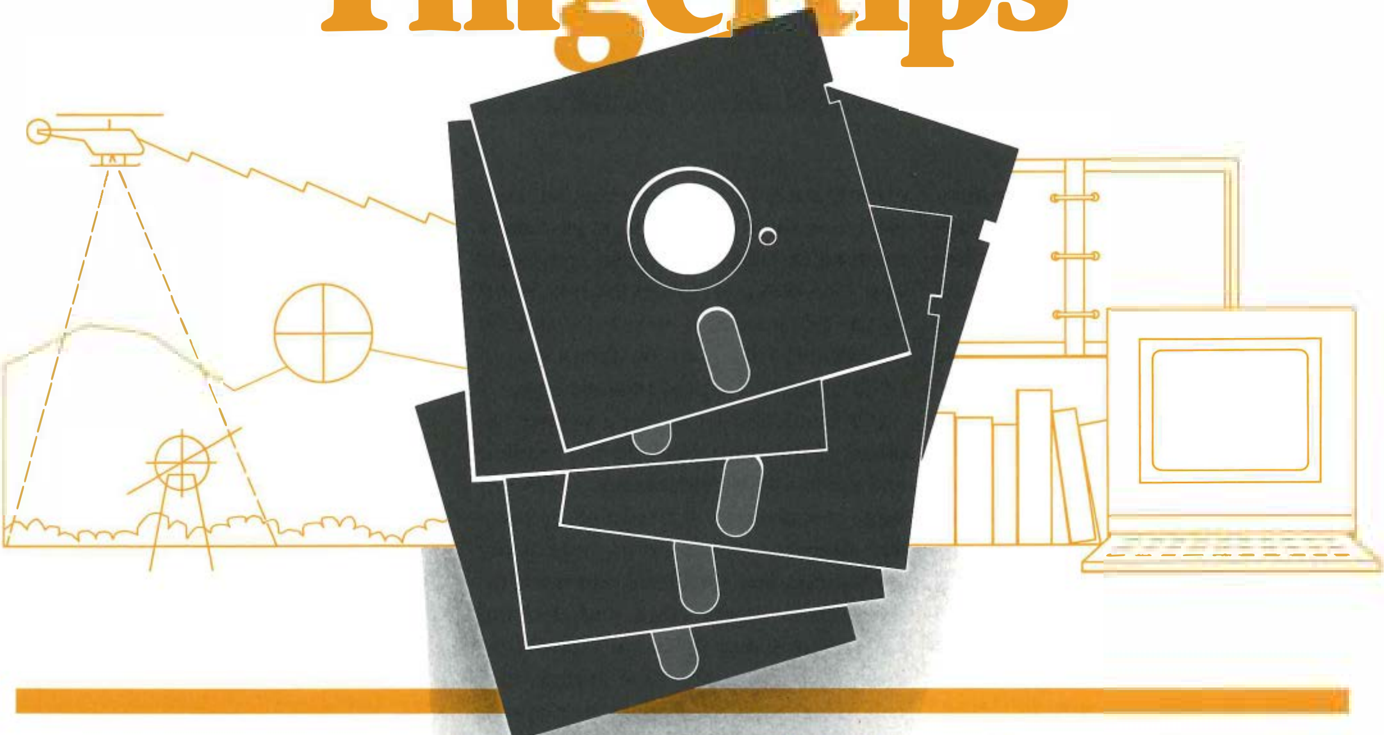
Although the better dielectric properties of PPP are the key to its applicability in utility cables, the tape itself is not proprietary to EPRI. It is made by Jen Coat, Inc., in this country; by BICC Power Cables Ltd. in Great Britain, and by a Japanese firm for marketing by Sumitomo Electric Industries. The quantities used to date for EPRI-sponsored prototypes came from Jen Coat and Sumitomo. BICC laminate was used in recently completed work on cable models.

Through 1984, according to the Edison Electric Institute, the United States total for underground transmission installations (69 kV and above) was 3223 circuit mi (5200 circuit km). At about 17 circuit mi (27.2 circuit km) altogether, the length of the three PPP-insulated cables is a modest figure. But it is a significant fraction of the total installed by utilities in a single year. The 1984 figure from EEI was 56 circuit mi (90 circuit km), mostly 138 and 230 kV, with 42 circuit mi (68 circuit km) of HPOF cable as the predominant type.

PPP insulation looks like a winner because of its adaptability to the familiar and proven HPOF technology. Utility design, installation, and operating practices therefore should remain essentially unchanged. But PPP introduces new efficiency in materials, labor, and electrical performance; and these are expected to bring highly desirable cost savings to a critical, specialized, and high-cost segment of U.S. power transmission capability. ■

This article was written by Ralph Whitaker. Technical background information was provided by Ralph Samm and John Shimshock, Electrical Systems Division.

Transmission Line Design at Your Fingertips



An integrated, interactive library of design software called TLWorkstation is all the utility engineer needs to put together a transmission line design from start to finish. And it can be run from a desktop computer.

David Bryan, the manager of engineering systems development at Alabama Power Co., remembers a time several years ago when his father poked fun at his work in transmission line design. "My father compared transmission line design to putting up a clothesline," Bryan says. "He didn't foresee the interrelated factors and trade-offs we deal with today in designing new lines and upgrades. Fifteen or 20 years ago, few people could have predicted the different demands that face the utility industry in the transmission field today or, for that matter, the computer technology that's helping us do the job."

New forces and constraints are changing the way utilities approach transmission line design. In a period of slow growth in demand for electricity, with minimal new generation planned before the end of the century, utilities must increasingly accommodate regional load growth with new or modified transmission facilities. For many utilities, this mission is complicated by an increased regulatory commitment to preserve the esthetics of the environment. These new restraints are motivating the utilities to design less-obtrusive structures and to work with fewer or less economically desirable rights-of-way.

While adjusting to the economic and regulatory climate, the industry must also plan transmission projects in an atmosphere of unprecedented uncertainty. Questions remain unanswered about the fate of planned generating plants, future involvement in power wheeling and cogeneration, and the precise patterns of load growth that are likely to shape the future.

To cope with these changes and uncertainties, many utilities are exploring methods for minimizing the lead times available for transmission projects. In addition, the industry is placing a new emphasis on innovative designs to achieve optimal efficiency and economy. Traditional designs and materials are being subjected to new scrutiny; money is being saved by moving design and analysis functions in-house; and batch-oriented computer analyses are being replaced by interactive tools that support the quick comparison of design alternatives.

Recognizing these trends, since the mid-1970s EPRI has worked to apply new computer technologies to transmission line design. Using the Transmission Line Mechanical Research Facility (TLMRF) in Haslet, Texas, as a design laboratory, researchers have used data from instrumented full-scale tests to develop new, more-accurate software tools for transmission line design. At the same time, developers have worked to expand the array of available software tools and to integrate these tools into a modular, interactive system that will provide utility engineers with a new flexibility and rapidity of response.

Generic tools for specific needs

Since the mid 1970s, the focus of these efforts has been the development of TLWorkstation*, an integrated package of interactive computer programs for designing both new transmission lines and modifications on existing lines. Already in use at more than a dozen utilities, TLWorkstation currently consists of an executive control program and 16 integrated task modules for structural and electrical planning, design, and analysis.

TLWorkstation is structured to help engineers follow a transmission line project from start to finish. The different task modules are integrated through the executive control program, which gives every module a uniform interface for inputting data and giving commands. A higher degree of integration will be achieved in 1987 when EPRI adds a generic data base and data base management system to the package. At present, data generated by each module are put into individual files. Using the data base, however, engineers will be able to automatically extract data from a central source and use them with all or any of the task modules.

Working on a system that is both modular and integrated, users can accomplish and record all the related tasks within a larger project or, if desired, use individual task modules to solve independent problems. For example, a user might use the tower analysis generator (TAG) module to generate designs for a new steel lattice tower. Data from TAG can then be input into the tower analysis program (ETAP), which can analyze stresses on the individual components, pointing the way to a stronger or more economical design. At this point, the transmission line optimization program (TLOP), accepting data generated by ETAP, can be used to determine an economically optimal pairing of structure and conductor.

"TLWorkstation can help utilities structure large transmission projects, but it will not impose a structure on them," comments Richard Kennon, manager of EPRI's Overhead Transmission Line Program. "Modularization makes the system flexible, allowing utilities to structure projects and choose tools that meet their individual needs."

As Kennon explains, new data base capabilities and new task modules will be added to the system as they become available, leading to a truly comprehensive system for both overhead and underground transmission line design. At the same time, the assumptions built into many of the modules will be updated as new data on structure and conductor performance arrive from utility experiences and full-scale tests.

"TLWorkstation is designed to be an evolving, dynamic system," Kennon explains. "By the end of the decade the system may support as many as 50 different task modules."

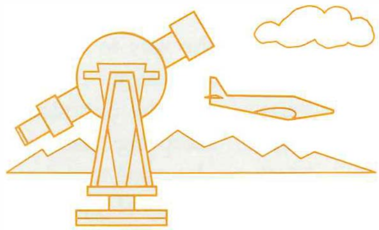
From the beginning, a key consideration in the development of TLWorkstation was making the system useful and attractive to the broadest possible range of utility users. At the same time, this collection of generic tools had to be sufficiently flexible to meet a wide variety of specific utility needs.

One important means to this goal is

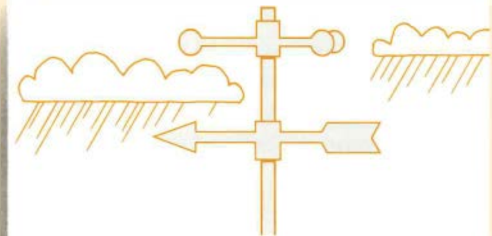
*TLWorkstation is an EPRI trademark.

Data for More Accurate Tools

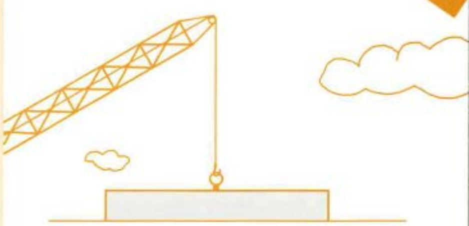
The continuously updated data for the TLWorkstation data base and task modules derive from laboratory and field measurements, including full-scale tests on foundations and complete towers, surveys of aerial and ground terrain along rights-of-way, and measurement of weather conditions. By basing its software on test results and field measurements rather than on assumptions generated by other computer software, EPRI provides the industry with a new accuracy and confidence in specialized programs for transmission line design.



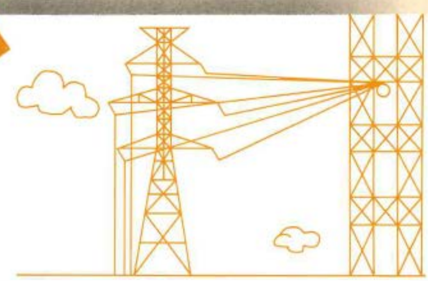
SURVEYING THE RIGHT-OF-WAY
Data for input into location engineering modules are gathered by utilities through aerial and ground surveys of terrain along rights-of-way.



GATHERING METEOROLOGICAL DATA
Measurements of wind and ice conditions are used in modules for determining the natural stresses that structures must withstand.



TESTING THE STRENGTH OF FOUNDATIONS
Data from uplift tests on full-scale foundations are incorporated into programs made specifically for foundation design and analysis.



FULL-SCALE TOWER TESTS
The Transmission Line Mechanical Research Facility in Haslet, Texas, is a laboratory for determining the physical loads that structures and their individual components can withstand.

portability, the ability of the software to be produced in versions compatible with different makes and models of computers. Aware of the wide variety of hardware found at different utilities, EPRI has designed versions of the software for many different microcomputers, minicomputers, and mainframes. This aids distribution of the software throughout the industry, increasing the chance that utilities can use the software on hardware they already own. In addition, microcomputer versions of the software are economically attractive; they force no demands on the mainframes in utility data processing departments; and they require no major hardware investments.

Software engineers have also designed the system's executive control program to give all the applications modules (in all their versions) a uniform and friendly user interface. The modules not only look the same on different computers, they are also equally easy to use, prompting the user in English instead of obscure computer symbols. "Our novice computer users are successfully interacting with the design and analysis modules within one or two hours after their first exposure," says David Webb, an electrical engineer at Illinois Power Co. who has been instrumental in evaluating TLWorkstation and putting it to use at his utility. "The friendliness of these programs has been crucial in winning over engineers who at first resisted the idea of workstation-based transmission line design."

By giving all TLWorkstation's task modules a uniform and friendly user interface, developers have made it easier for utility engineers to work on many different phases of complex projects. In the past such projects have required the use of different software tools (often running on different machines) that would present users with many different and difficult regimens for inputting data and giving commands. Most utility transmission departments lack both the hardware resources and the broad computer expertise necessary to handle this hodgepodge of tools in-house. As a result, outside consultants are often employed to handle different tasks within large projects.

In contrast, the integrated tools that compose TLWorkstation require no special computer expertise. Utility engineers and managers who are technically competent in their fields can thus interact with the different modules at many different stages of larger projects.

An interactive system

For both large and small projects, a key advantage of an interactive workstation system is the "what if?" analysis it makes possible within reasonable timeframes. Working with an interactive system, the utility engineer can conduct an analysis based on a given system of parameters, quickly get answers, and then alter specific parameters before calculating new results. Interactive graphics programs, such as TAG, give structural designers a similar ability to experiment with different tower configurations and gradually build an innovative design.

In contrast, the batch-oriented data processing available to many utility transmission engineers can be exceedingly cumbersome and slow. Without an interactive system of software tools, data must be punched on cards or entered into a mainframe computer through a dumb terminal. Utilities can thus spend a great deal of time researching and organizing parameters, entering them into a computer, or waiting for service from in-house data processing departments or outside vendors. If a design and analysis project is complex, involving different tasks, or if an innovative design is being developed through analysis, the man-hours required can become prohibitively large. For "what if?" analyses, each set of parameters may require hours or days of tedious, iterative work. Then, if computer analyses based on a given set of parameters do not yield satisfactory results, the entire process of design and analysis may have to be repeated.

"Overall, utilities using TLWorkstation are completing tasks in hours that once took days or projects in a matter of a few days that once took weeks," reports Kennon. "In other cases, they're attempting projects that were prohibitively time-consuming and expensive in the past."

Kurt Swanson, transmission project engineer at Florida Power & Light Co. (FP&L), reports that his utility hopes to use TLWorkstation this fall "to conduct a close study of the economics and performance of conductor alternatives for a 26-mi (42-km) line that we hope to uprate in the northern part of our state. We hope to look at many different conductor alternatives, considering line losses as part of our cost. It's a type of analysis that probably would have been impossibly time-consuming in the past."

An Illinois Power Co. study confirms the time and manpower savings made possible by an interactive system. To secure right-of-way for a 345-kV line, the utility spent 225 man-hours in the early 1980s to prepare design alternatives and cost data for presentation to the Illinois Commerce Commission. Looking toward future presentations, the utility used TLWorkstation in 1985 to repeat the earlier analyses. The time required for the workstation analysis was 10 man-hours, a time saving of more than 96%.

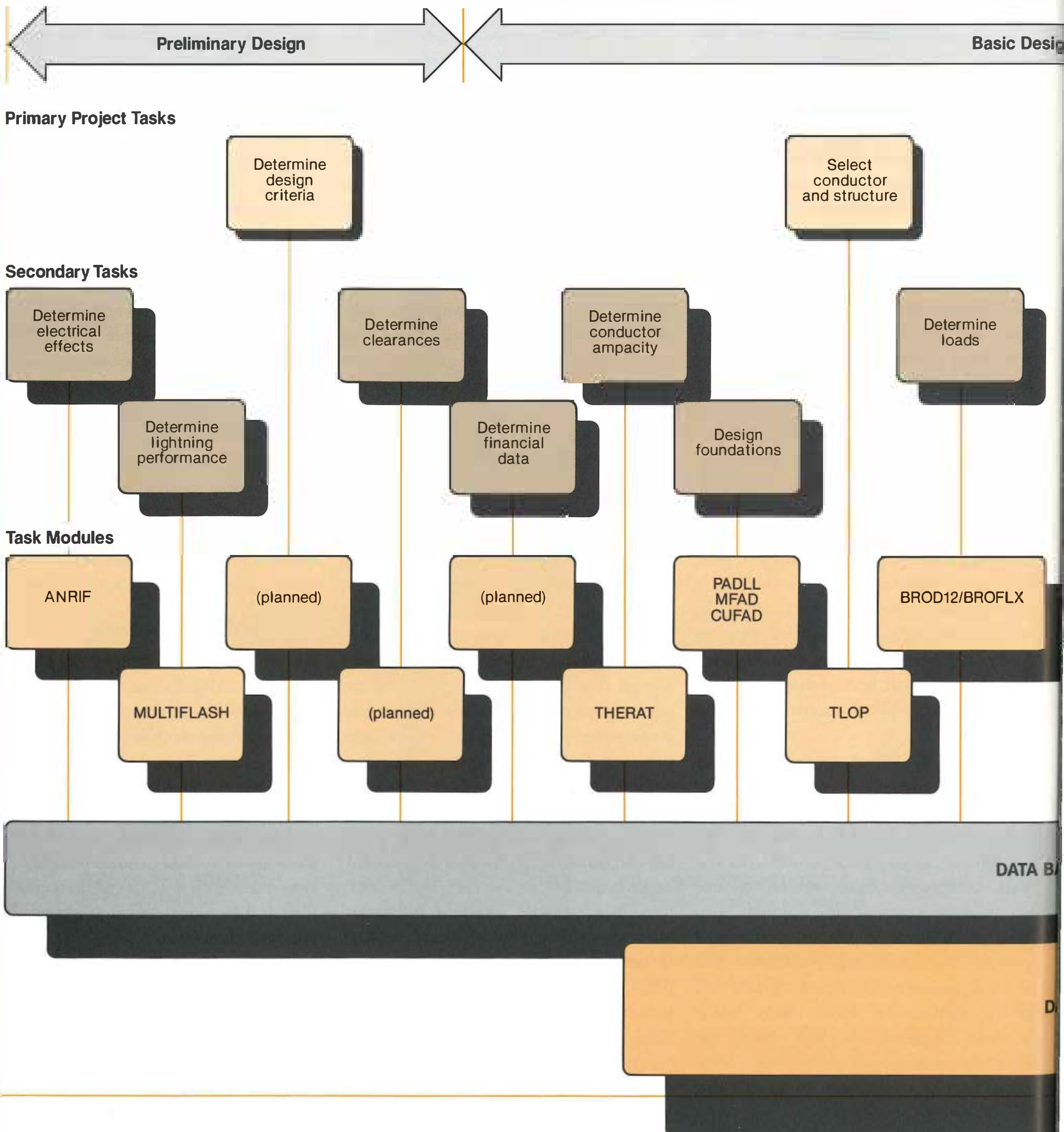
The advantages of integration

As an integrated system of software modules, TLWorkstation gives users the added advantage of applying data developed with one module to other areas in a larger project. This does not mean that the different modules communicate directly with one another or that all the modules must be used to achieve results from one. Instead, communication between modules is achieved through data files and (by 1987) through queries to a common data base.

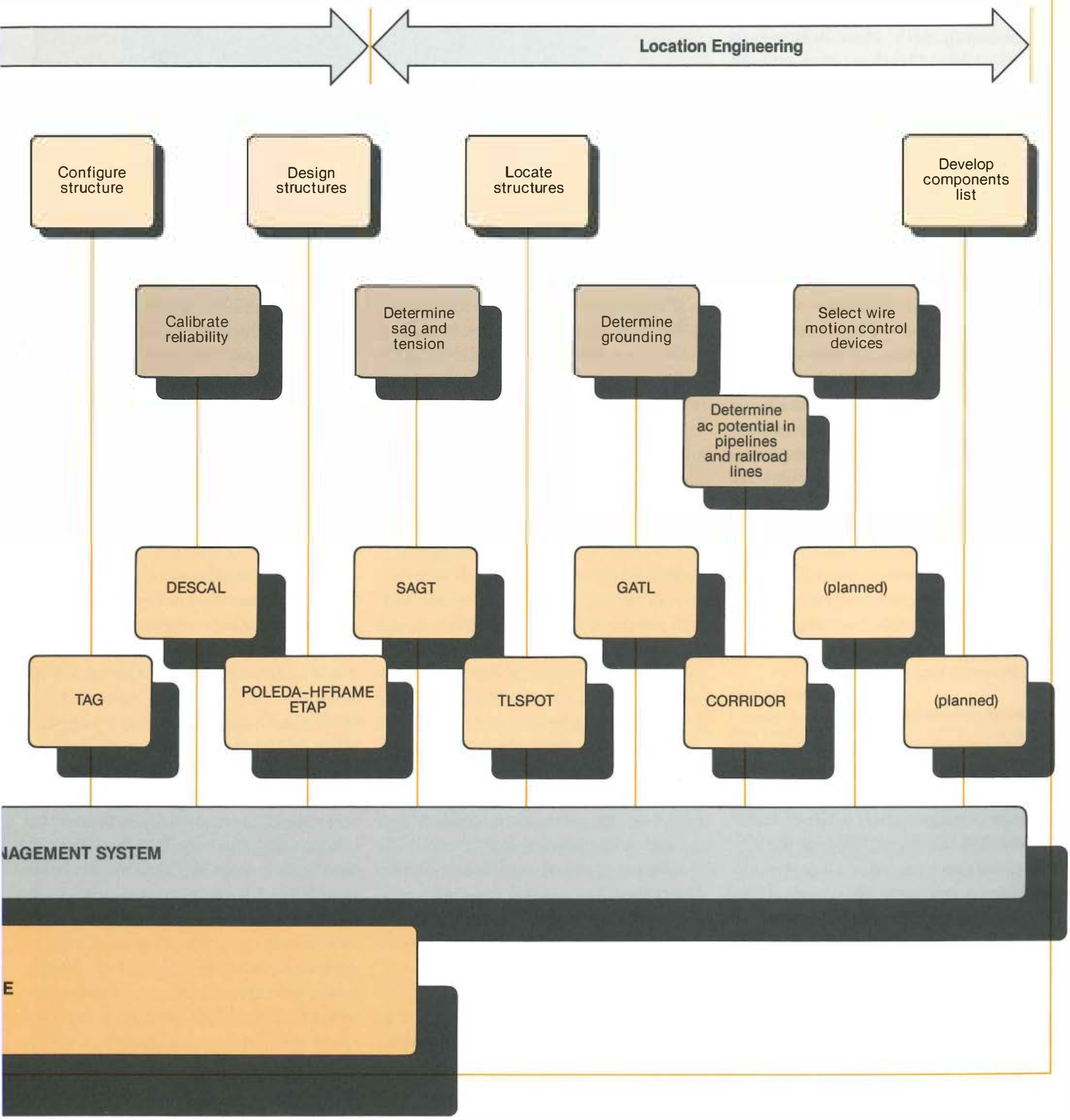
Now in development, the data base will have a double function. It will serve as a repository for all data generated with the various task modules in the course of a project, and it will be a storehouse for generic information, such as materi-

Toward a Comprehensive, Integrated System

TLWorkstation has been designed as an evolving, dynamic system that reflects the many related activities that compose a transmission line design project from beginning to end. The system currently consists of an executive control program and 16 task modules that cover a core of planning, design, and analysis activities for overhead transmission. Additional modules are being developed, with perhaps 50 to be available by the end of the decade in a comprehensive system for both overhead and underground transmission line design. The executive control program



provides a uniform interface with the modules, which can be used separately or in various combinations. Although data developed with the task modules are currently stored in individual files, EPRI plans the release of a generic data base and data base management system in 1987 that will allow users to automatically extract data from a central source for use with the task modules.



als properties, standards, and specifications. With the data base running at the same time as individual task modules, engineers will be able to automatically retrieve all data pertinent to the task at hand. This will significantly reduce the time currently needed for researching materials and inputting data for use with the TLWorkstation package.

In keeping with other features of TLWorkstation, the data base will be flexible. The utility will be able to customize a data base for each project and will update the data base as costs change and new materials become available. EPRI will also regularly update the data base as new data arrive from various test projects.

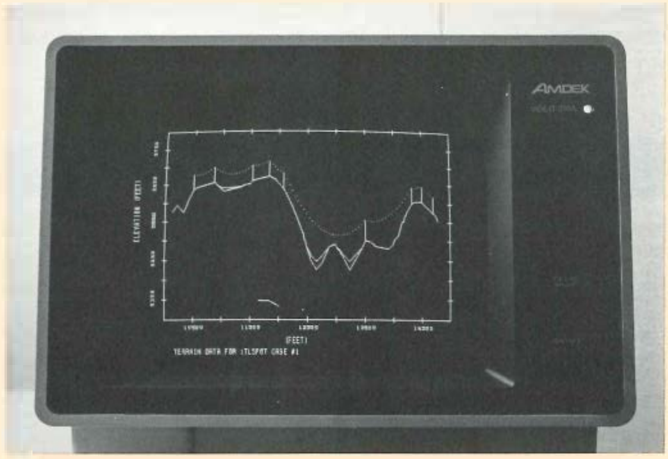
Currently, EPRI is evaluating several data base management systems that will allow users of TLWorkstation access to the data base. As in past development efforts on the workstation software, portability and ease of use have been established as important selection criteria.

In a parallel development, discussions are under way with leading manufacturers of specialized turnkey systems for computer-aided design (CAD) who are considering the adaptation of TLWorkstation modules for use with their systems. An agreement of this kind could result in hardware-software systems with the sophisticated data base capabilities that EPRI is now planning for all versions of TLWorkstation.

Improved communication

In addition to helping utilities complete larger projects much more quickly, the integrated features of TLWorkstation can improve communication between transmission line designers. Because the system maintains a record of all past work, individuals can pick up where others left off. Because the modules work so smoothly together, individuals with different functions and specialties can more easily unify their efforts. This can lead to better communication with vendors who also use the software or to more give and take between structural and electrical de-

A Software Tool for Spotting Towers



Choosing the best locations for structures along a transmission line is a complex task involving many different considerations. If the terrain rises and falls (or otherwise changes in character), tower placement will affect other decisions, such as the height and design of individual towers, the distances between them, and the distance from conductors to the ground. The challenge facing tower spotters (highly skilled specialists who work in this field) is to achieve the lowest-cost transmission line by strategically positioning the structures.

Even these experts, however, produce varying results, and until recently utilities had no method for determining if a true optimum had been realized. In response, EPRI plans to add TLSPOT (transmission line structure spotting) to the TLWorkstation package in the first quarter of 1987. Now being tested at utility sites, this user-friendly software program will allow transmission engineers with no special tower spotting or computer expertise to determine the optimal locations and types of structures for any planned transmission line.

To work with the program, users first input a plan for the line being built, including all obstructions along the right-of-way. This plan is supplemented with a profile of the terrain that includes the elevation of each possible tower location. The distances between possible locations are determined by the extent of the surveying that has been done. Additional inputs include structural data on the family of towers being used, the installed costs of the tower types and conductors being planned, and the maximum tension that can be withstood by the conductors.

After data are added on any special clearances or obstructions that might affect the line, an optimizing algorithm is used to arrive at the right towers in the right locations for the lowest possible cost.

In spite of the complexity of the calculations involved, TLSPOT has been designed to meet the TLWorkstation standards of portability, ease of use, and integration with the other modules in the package. Reports from early tests show the program consistently provides results equal to or better than those achieved by experienced tower spotting specialists. □

signers within utilities.

"Historically, there has been a division in most utilities between structural and electrical designers, with one group establishing parameters that limit the choices of the other," comments Roger Clayton, manager of power delivery at Power Technologies, Inc., a company that helped develop the software for TLWorkstation. "The problem with that type of vertical communication is that it doesn't always lead to the most efficient results. Integrated, workstation-based software can help these two groups join together and work toward a global optimum."

Swanson illustrates a similar point when he discusses the optimization study that FP&L plans this fall. "In the past our structural engineers worked with a conductor that was established as a standard for a given voltage. But now we hope to consider line losses and choose from different conductors to optimize the entire line. The better we get at looking at the line as a whole, the more choices we're likely to find."

Data from real life

A key to encouraging utilities to explore the choices made available by TLWorkstation is a high level of confidence in the accuracy of the software modules. A distinguishing characteristic of several of the TLWorkstation software modules is that they incorporate assumptions based on field tests and full-scale testing at TLMRF. Ongoing measurements of weather data, material durability, and the strength under stress of complete towers and foundations have been and continue to be incorporated into the TLWorkstation software. In comparison, most of the other software used in the transmission field is based on assumptions generated with still other software programs. As a result, large investments can be made on the basis of unverified assumptions about structural strength and the overall reliability and efficiency of a transmission line.

As well as producing data for improved software tools, TLMRF gives utilities a chance to ensure the performance of innovative designs. At the test facility, winches pull on full-scale structures and replicate the physical loads that the structures and each of their individual components are designed to withstand. Utilities can bring their new designs to TLMRF and test the strength of the individual steel supports, or members, in lattice tower designs. In this way, weak members can be identified and strengthened. Redundant members can be identified and removed, resulting in a tower that costs less with no sacrifice of strength.

Bryan relates his experience with a 230-kV tower design generated on TLWorkstation that his utility tested at TLMRF. "The tower failed just short of our goal of 100% design loading, so we replaced one member with a member that was thicker by 1/16 in (1.6 mm), tested it again, and it worked fine. We saved enough on this modified tower design to recover the costs of testing. And now we have an improved design in our data base that might produce more savings in the future."

In a different combined use of TLWorkstation and TLMRF, Arkansas Power & Light Co. (APL) identified a longitudinal weakness in an existing tower that was leaving a 500-kV line especially vulnerable to storm damage. After a tornado caused 30 towers along the line to collapse like dominoes, analyses performed with TAG and ETAP showed that the towers were failing at 50–60% of design loading. Using TLWorkstation, APL generated a modified design that was tested successfully at TLMRF. Although the utility invested about $1.7 million to modify the actual towers, it expects to more than recover its investment over the next decade through reduced storm damage.

Future directions

In the future, as TLWorkstation expands, such new functions as bills of materials and documentation management might be integrated into the system. This type of integrated system, comparable to the CAD/CAM systems that are improving productivity in other U.S. industries, could automatically generate bills of materials, blue prints, and other documents from data generated by the various task modules. Another possibility is direct numerical control of the fabrication machines of vendors, a data communications link that could possibly eliminate reams of utility paperwork.

Although quite achievable with current computer technology, these levels of integration will most likely require some restructuring of data processing and accounting functions within most utilities. For this reason, changes in the industry are not likely to keep even pace with the cost-effective advantages that current computer technology can offer.

Nonetheless, the external pressures being put on the industry should help push new electronic tools past institutional barriers. "There is no doubt that the future will be more challenging for developers of electronic tools for transmission line design, as well as for designers, builders, and operators," comments Kennon. "As utilities face the greater burdens being placed on limited transmission facilities, they will increasingly look to electronic tools to optimize reliability, environmental compatibility, economy, and safety." ■

Further reading

Integrated Transmission Line Software: TLWorkstation Functional Specification. Final report for RP2151-2, prepared by Sargent & Lundy Engineers, August 1986. EPRI EL-4468.

Structural Development Studies at the EPRI Transmission Line Mechanical Research Facility. Interim report for RP2016-3, prepared by Sverdrup Technology, Inc., August 1986. EPRI EL-4756.

"TLWorkstation." Videotape for RP2151, November 1985. Tech Tape ES85-06; length, 16:30.

Laterally Loaded Drilled Pier Research, 2 vols. Final report for RP1280-1, prepared by GAI Consultants, Inc., January 1982. EPRI EL-2197.

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

TECH TRANSFER NEWS

Product Champions

There are times when technology transfer succeeds largely through the commitment of a single individual in a utility, known at EPRI as a product champion. In addition to strong support from their management, these champions share a profile of foresight and perseverance: dedication to the realization of a concept, ability to see the future benefits of new products and techniques, and willingness to initiate an effort and keep it moving to a successful conclusion.

Because a great many people are involved in transferring EPRI products to the utility industry, key contributions of individuals are sometimes overlooked. The following case studies illuminate the efforts of three product champions, as well as the benefits they have brought to their utilities and the entire industry.

Steam Generator Owners Group

In 1972 Samuel Rothstein of Consolidated Edison Co. of New York, Inc., was assigned the problem of tube leaks in the nuclear steam generator in Unit 1 at Con Edison's Indian Point station. Subsequent to his resolving this problem, he identified a range of other potential problems in the nuclear steam generator that was being installed in Unit 2. With the desire to help his company in particular and the industry at large improve the reliability, availability, and lifetime of steam generators, he initiated the efforts that would culminate in the formation of the Steam Generator Owners Group (SGOG).

For about two years (1973–1975) Rothstein was a participant in an EEI ad hoc committee on steam generators, and then he was elected chairman of the ad hoc Chemical Cleaning Group that was studying chemical cleaning as a means of dealing with steam generator problems caused by corrosion. In these roles he met with numerous representatives from the utilities, various NSSS suppliers, chemical cleaning companies, and EPRI to discuss steam generator problems and find the best way to address them. While chairman of the chemical cleaning group, he looked beyond chemical cleaning to a wide range of issues related to steam generator operations and maintenance and proposed the formation of a new group within EPRI to investigate the many aspects of steam generator problems and to develop guidelines and solutions.

Rothstein

With the support of both Con Edison and the Chemical Cleaning Group, Rothstein made several presentations before EPRI's Systems and Materials task force. He then prepared a proposal, signed by the utility representatives in the Chemical Cleaning Group, for EPRI's Board of Directors. The Board approved the concept, and in early 1977 the first Steam Generator Owners Group (SGOG) was formed. William Caldwell, then senior vice president of Con Edison, was the first chairman of the SGOG Executive Committee, and Rothstein served on the Technical Advisory Committee. The group grew to include 24 U.S. utilities, 3 European utilities, and a group representing Japanese utilities.

As a result of R&D sponsored by SGOG, steam generators are more durable and reliable today than ever before. SGOG has played an important role in developing an improved understanding of the thermal hydraulics of steam generator systems, the processes causing corrosion, and the effects of water chemistry on those processes. New advances have also been made in chemical cleaning and in the nondestructive evaluation of steam generator systems.

"Seventy-five parts per million of chloride was acceptable in steam generator blowdown water in 1972; today—with our new understanding of water chemistry and its importance in controlling corrosion—even 20 parts per billion is considered excessive," Rothstein comments. Reflecting on the many contributions of SGOG, he adds, "In 1978 the utility projected that the limit to reliable service life of the steam generators at Indian Point-2 could be reached within only 2–3 years. Today, thanks to the work sponsored by the owners group and the many remedial measures implemented by Con Edison, the utility believes its steam generators might last the lifetime of the plant."

TLWorkstation

During 1975–1985 tornadoes downed 250 transmission towers belonging to Arkansas Power & Light Co. (AP&L). At times, 20–25 towers were pulled down like dominoes as a result of a single tower's failure. In addition to absorbing the costs of lost generation, the utility paid $10 million to rebuild the downed structures.

Seeking to prevent such losses in the future, the utility sent one of its engineers, John Meeker, to a three-day seminar conducted by Southwest Research Institute on a new computerized EPRI system for transmission line design. At the EPRI seminar Meeker learned about the features of TLWorkstation, a microcomputer-based software system that promised an in-house solution to AP&L's tower problems. Using the software and a personal computer, the utility—without any special expertise in computer-aided design—could model the structural members of a transmission tower, test its design strength, detect its weaknesses, and model changes.


Meeker

Returning from the seminar, Meeker recommended AP&L use TLWorkstation to analyze its current towers and alter the design for increased strength. After being authorized to acquire the hardware and software, Meeker began to use the system and iron out some of its bugs. In the meantime, an EPRI contractor, Sverdrup Technologies, Inc., rewrote the program, "bringing it," says Meeker, "from a Model T to a 280-Z." Meeker received the new software in June 1984 and within a week was using the system to model different tower structures. Within a short while, after some additional refinement of the software, he was able to identify a consistently weak area in the design of AP&L's towers. According to his analyses, the towers were failing at 50–60% of their design loading. By August he had worked with the AP&L maintenance supervisor on two design modifications to strengthen the towers and minimize future tornado damage.

Meeker then participated in full-scale testing of the new designs at the Transmission Line Mechanical Research Facility (TLMRF) in Haslet, Texas. A great deal was riding on the outcome of the TLMRF tests: over 800 towers needed modification at a total cost of $800,000–$1,800,000, depending on the modification selected. As it turned out, the best of the designs generated on TLWorkstation was shown by a full-scale test to fail at 115% of design loading, a 100% improvement in tower strength. After working with the TLMRF staff to test and verify this retrofit design, AP&L modified the 800 structures at a cost of $1,400,000.

With its modified towers in place, AP&L expects to save approximately $20 million on storm damage over the next 15 years. Although Meeker feels that it will take several years before the full effect of the program can be assessed, there is no doubt that the benefits from his efforts with TLWorkstation and TLMRF will far exceed AP&L's investment.

Power Electronics Applications R&D Center

Michael Lechner of Public Service Co. of New Mexico has been the guiding spirit behind the Power Electronics Applications R&D Center (PEAC) opening this fall at the Tennessee Center for Research and Development in Knoxville, Tennessee. PEAC will be the national focus for technical assessments to evaluate industrial needs for power electronic (PE) systems and applications. It will also provide utilities, industry, and the public with PE information to help in defining specific R&D projects.


Lechner

Lechner has been closely involved with EPRI since 1976, beginning with the Solar Heating and Cooling Working Group, later as a loaned executive during 1980 and 1981, then as a member of the Energy Utilization and Conservation Task Force, and (in 1985) chairman of the Industrial Applications Program Committee. During this time he also served as a member of the PEAC planning group, and now he is serving on the EMU Division Committee. His interest in power electronics began in the early 1980s when he heard EPRI Program Manager Ralph Ferraro discuss the potential value to the utility industry of new PE applications, such as adjustable-speed drives, and the role of PE in electrotechnologies, such as induction heating and melting, plasma processing, dielectric heating, and electrochemical processing.

As Ferraro explained, energy users and process equipment manufacturers are generally not familiar with ways to integrate PE systems into their equipment. To match the quantity and quality of electric power with the requirements of specific processes, both utilities and industry have to become more aware of the opportunities and interface issues when integrating PE equipment into their industrial processes. By playing a role in the development and application of PE systems in U.S. industries (including their own power plants), utilities could help improve productivity, enhance load compatability and efficiency, and increase the competitiveness of U.S. industries in the global economy.

"Ralph's knowledge of power electronics applications was very instructive," Lechner says, "and his enthusiasm was contagious. He made it clear to me that the establishment of PEAC was in the best interests of the utility and other industries."

Working with Ferraro to plan PEAC, Lechner became deeply involved in helping to bring together utilities, end users, manufacturers, and other supporters to make sure that the new applications R&D center would have a strong foundation. Lechner also helped gain approval for PEAC from the highest levels of EPRI management.

Today, with PEAC about to open, Lechner comments that PE technology is unique in the multiple benefits it can provide to both utilities and industry. "In addition to improving efficiency in power plants and productivity in industry, PE technology can help utilities expand into the role of full-service energy companies. Some utilities are already involved in the sale, lease, and maintenance of power electronics equipment, and others are likely to follow," he predicts. "As this technology mushrooms, there are all kinds of ways that utilities and their customers stand to benefit." ■

AT THE INSTITUTE

Klein Appointed Vice President of IRIS Group

Institute President Floyd Culler announced in July the appointment of Milton Klein to succeed Richard Rudman as the vice president of EPRI's Industry Relations and Information Services Group (IRIS). The appointment became effective on August 1.

Klein

Prior to his appointment, Klein served as vice president, Special Projects, which include the Institute's commercialization, licensing, and international activities. In his new position, he will continue to oversee these functions, while assuming responsibility for the Corporate Communications and Technical Information divisions within IRIS.

The IRIS Group handles EPRI's relations with its membership, the government, utilities in other countries, the media, and industries involved in using and commercializing the products and methods developed through EPRI research.

"There are three basic dimensions to the challenge facing the IRIS Group," said Klein in reference to his appointment. "First, we have to be responsive to input from our membership and ensure that the needs of member utilities are being met. We have to make the results of our R&D available to our membership through technology transfer, using personal contact and a broad program of technical reporting and communications. And we have to ensure a strong membership base."

Before joining EPRI in 1980 Klein was director of the joint NASA–Atomic Energy Commission Space Nuclear Systems Organization, assistant general manager of the Atomic Energy Commission, and later, director of Research, Development, and Technology Applications of the International Energy Agency in Paris. He has a chemical engineering degree from Washington University and an MBA from Harvard University.

Rudman, one of the Institute's first employees and Klein's predecessor as IRIS vice president, has accepted a position as president of Aster Publishing Co., a leading publisher of technical magazines in Eugene, Oregon. "I feel good that key pieces are in place, and I'm very proud of the management team within the IRIS Group," said Rudman after Klein's appointment. "Helping build EPRI into a world-class R&D organization has been a very special privilege." ■

Hingorani Named Head of Electrical Systems Division

In May of this year Narain Hingorani was appointed vice president and director of the Electrical Systems Division, succeeding John Dougherty, who recently retired from the Institute.

Hingorani has been with EPRI since 1974, first as the manager of the Transmission Substations Program, then as director of the Transmission Department, and is known for his pioneering work in high-voltage direct current power transmission. Hingorani was with the Bonneville Power Administration for six years before joining EPRI. During his tenure at BPA, he was responsible for coordinating matters related to the commissioning of the HVDC Pacific Intertie, design of series capacitors protection,

Hingorani

and coordination of systems engineering for ultrahigh-voltage ac transmission. He has also served as a consultant to several HVDC projects in the United States, Canada, and Brazil.

Hingorani is the author of a seminal book on HVDC power transmission and more than 100 papers and articles on HVDC and ac transmission. He spent several years teaching in two British universities; his educational background includes a BS in electrical engineering from Baroda University (India) and an MS and PhD from the University of Manchester Institute of Science and Technology (England).

"In my career, he is the best informed in the broad field of power engineering of anyone I've met," commented John Dougherty about his successor. "He has an enormous depth of knowledge in all aspects of engineering."

Hingorani is also an active member of such professional organizations as CIGRE, IEC, and in particular, IEEE. In 1985 he was awarded the IEEE Power Engineering Society's Uno Lamm Award for his outstanding contribution to HVDC technology. ■

Corporate Communications Division Formed

Two divisions within IRIS—Member Relations and Communications—were consolidated in June to form a new Corporate Communications Division headed by Richard Claeys, director. The new division will encompass member service and research applications activities, as well as the *EPRI Journal*, Public Information, Communications Services, and Washington Communications departments.

The division will use publications and electronic media to communicate with members, potential members, and outside groups on the full range of EPRI's R&D: the programs, the application of results, the implications, and the potential benefits. In addition, the division will work directly with member utilities to ensure that they are sufficiently informed about EPRI's programs to reap the greatest possible benefits from their membership.

Claeys

"The new Corporate Communications Division is structured to play a key role in serving EPRI's members and in expanding the Institute's membership base," said Claeys. "Within the new division, both creative and technical professionals can now work more closely together in pursuit of these goals."

Claeys came to EPRI in 1985 after 21 years of experience in corporate communications. From 1979 to 1985 he served as vice president for corporate communications at Metropolitan Life Insurance Co. of New York and earlier was director of public relations at Connecticut General Insurance Corp.

CALENDAR

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

OCTOBER

14–15
Assuring Power Quality
Baltimore, Maryland
Contact: Marek Samotyj (415) 855-2980

14–15
1986 EPRI Cogeneration Symposium
Washington, D.C.
Contact: David Hu (415) 855-2420

14–16
Seminar: Solid-Waste Environmental Studies Technology Transfer
Milwaukee, Wisconsin
Contact: Ishwar Murarka (415) 855-2150

15–16
6th Annual EPRI Contractors' Conference on Coal Gasification
Palo Alto, California
Contact: Neville Holt (415) 855-2503

21–22
3d Annual ORSERG-NSAC Safety Engineering and Review Workshop
Houston, Texas
Contact: William Reuland (415) 855-2977

21–24
Seminar: TLWorkstation
Dallas, Texas
Contact: Paul Lyons (817) 439-5900

23–24
4th EPRI Reactor Physics Software Users Group Meeting
Chicago, Illinois
Contact: Walter Eich (415) 855-2090

26–29
Seminar: Fuel Cells
Tucson, Arizona
Contact: Ed Gillis (415) 855-2542

NOVEMBER

5–6
Industrial Applications of Adjustable-Speed Drives
New Orleans, Louisiana
Contact: Marek Samotyj (415) 855-2980

5–7
Symposium: Market Research
Kansas City, Missouri
Contact: Larry Lewis (415) 855-8902

10–12
1986 Seminar on BWR Corrosion, Chemistry, and Radiation Control
Palo Alto, California
Contact: Daniel Cubicciotti (415) 855-2069

11–13
Workshop: Power Plant Performance Monitoring and System Dispatch Improvement
Alexandria, Virginia
Contact: Robert Leyse (415) 855-2995

17
Seminar: Flue Gas Desulfurization Maintenance Guidelines
Atlanta, Georgia
Contact: Robert Moser (415) 855-2277

17–19
Marketing Electrotechnologies to Industry
Atlanta, Georgia
Contact: Leslie Harry (415) 855-2558

18–21
10th Symposium on Flue Gas Desulfurization
Atlanta, Georgia
Contact: Robert Moser (415) 855-2277

DECEMBER

1–2
Seminar: Coal Transportation Costing and Modeling
San Diego, California
Contact: Edward Altouney (415) 855-2626

1–3
Fly Ash and Coal Conversion By-products
Boston, Massachusetts
Contact: Ishwar Murarka (415) 855-2150

3–5
1986 Fuel Supply Seminars
San Diego, California
Contact: Jeremy Platt (415) 855-2628

9–11
Utility Motor Reliability
Phoenix, Arizona
Contact: Jan Stein (415) 855-2390

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Vice President

HEBER PROJECT COMPLETES FIRST YEAR

The first year of tests and operation of the Heber binary-cycle geothermal power plant has been successfully completed. Continued success of the demonstration plant (located near Heber, in southeastern California's Imperial Valley) will establish the technical and economic feasibility of using moderate-temperature brines to generate electricity on a commercial scale. And commercial-scale use of these lower-temperature brines will effectively double the identified hydrothermal resources in the United States available for recovery. A heavy schedule of additional plant demonstration tests, evaluations, and data collection is planned for the second year of test and operation (RP1900-1).

The 45-MW (e) Heber binary-cycle demonstration project is supported by a group of utilities, governmental agencies, private businesses, and EPRI. The participants, in addition to EPRI, are San Diego Gas & Electric (SDG&E), Imperial Irrigation District (IID), Southern California Edison Co. (SCE), Pacific Gas and Electric Co. (PG&E), the state of California and its Department of Water Resources, two industry organizations, and DOE. The plant site, in California's Imperial Valley, is within IID's service territory (Figure 1).

The need for a commercial-scale plant to demonstrate the feasibility of using moderate-temperature brines as a heat source for generating electricity was first identified in 1974 by utility and industry representatives at an EPRI workshop. Subsequently, EPRI funded a series of conceptual design studies, equipment designs, and field experiments that were essential to the detailed design of a large-scale geothermal generating facility.

The contract for design, engineering, and equipment procurement was let in early 1980 to Fluor Engineers, Inc., and in late 1982 the construction management contract was awarded to Dravo Constructors, Inc. The project's detailed design and major procurements were essentially complete by mid 1984. In 1983 a heat purchase agreement was entered into with Chevron Geothermal Co. and Union Oil Co. of California (owners of the Heber geothermal resource) whereby those companies would supply geothermal brine to the Heber plant. The Heber binary-cycle geothermal project is described in detail in AP-4612-SR.

Plant construction and startup

Construction of the Heber binary-cycle power plant began on June 13, 1983; SDG&E acted as project manager and host utility. Four major contracts covered the construction: one for site development, one for civil and structural, one for mechanical, and one for electrical. Other contracts provided for heavy equipment handling, paving, painting, and landscaping.

In 1983 Chevron began detailed design of the geothermal brine production and injection facilities. In 1984 construction work began on Chevron's site (adjacent to the power plant's northern property line), and drilling started on the production and injection wells. Design and construction were coordinated by Chevron and SDG&E to ensure that the brine production and injection facilities would be operational when the power plant was ready for the brine. As the unit operator, Chevron is also responsible for operating and maintaining these facilities.

The Reservoir Development Plan called for slant drilling in two phases of 13 production wells from Chevron's site on the border of the power plant and 9 injection wells from another site located 4.0 km (2.5 mi) northwest of the plant. The wells are designed to recover brine

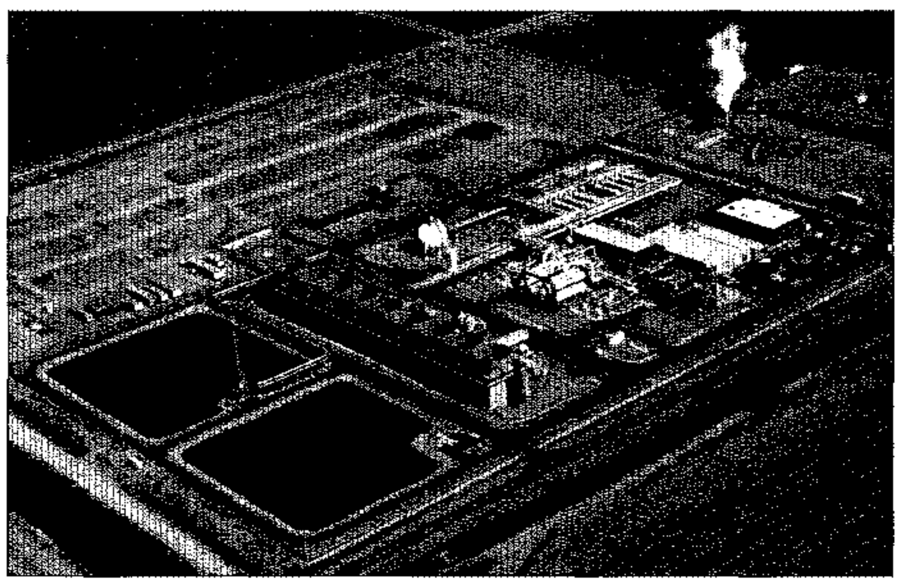


Figure 1 Heber binary-cycle geothermal power plant. Thirteen slant-drilled wells will provide about 965 kg/s (7.65×10^6 lb/h) of moderate-temperature brine (about 180°C, 360°F). Heat is extracted from the brine to vaporize a low-boiling-point hydrocarbon fluid mixture; the vaporized working fluid turns a turbine that drives a generator. Rated plant output is 46.6 MW (net).

from four zones ranging in depth from 610 to 3050 m (2000–10,000 ft). The design flow rate was set at 965 kg/s (7.65×10^6 lb/h). Fifty percent of the design rate, 480 kg/s (3.83×10^6 lb/h), was to have been achieved early in 1985 and full flow on May 1, 1986. However, a revised schedule now calls for 100% flow in May 1987.

In the first phase Chevron drilled seven production wells and installed downwell pumps in six, from which brine has been supplied to the power plant; five injection wells were drilled to return the cool brine to the reservoir. The original estimates were that the output of each production well would average 80.6 kg/s (640,000 lb/h). However, the average production from these six wells has been only 335 kg/s (2.7×10^6 lb/h), about 35% of the brine flow rate required for rated output. In August 1986 Chevron put the seventh well into production, which brought the total brine flow closer to the 50% level.

In April 1986 Chevron began construction of the second-phase surface facilities, which are required to supply full brine flow. Drilling of the additional production and injection wells began in September.

Each production well has a shaft-driven pump set down into the well at depths from 215 to 305 m (700–1000 ft). Each pump is driven by a 650-hp electric motor located on the surface. Industry experience had demonstrated an average run time of 800 h between failures for shaft-driven pumps, including failures of pumps and line-shaft bearings (AP-3572). During this first year, there were some problems with seals at the surface and with bearings and seals in the pumps. However, the average run time between failures of pumps and line-shaft bearings was over 1570 h. The pumps themselves have operated well, and one of the downwell pumps has run for more than 6000 hours without a failure.

During the design of the Heber plant, an engineering scale model of all the aboveground power plant facilities was built. The model was first used as a design tool; then it was moved to the site and used as a construction aid. For example, its use led to a decision to relocate the power and control cables from overhead cable trays to underground duct banks.

SDG&E decided on a staff organization composed of an upper level of SDG&E personnel supported by contracted operation and maintenance personnel. Two other geothermal power plants in the Imperial Valley have successfully operated in a similar manner. After some operational experience at Heber, the staff was altered in various ways and now stands at 41, of which some are assigned to support the test and demonstration program.

The plant's operation and maintenance personnel were brought on-site during the later construction period. They monitored construction progress and began their formal training sessions, which were conducted by SDG&E, the operations and maintenance contractor, and equipment suppliers. Plant personnel were also trained in handling the hydrocarbon working fluid and gained hands-on experience in controlling hydrocarbon fires at a fire-fighting school.

SDG&E formed a startup group that was responsible for checking the construction of components and systems and for starting the equipment. In November 1984 the plant's 4160/480-V electric distribution system was energized, signaling the formal beginning of the project's startup phase. Plant operation and maintenance personnel ran the equipment and systems during the startup phase, thereby increasing their familiarity with the plant.

On May 8, 1985 the first brine flowed from the production wells to the power plant facilities. Turbine roll occurred on May 21, 1985. The plant was synchronized to IID's 34.5-kV subtransmission system on June 14, 1985, two years from the start of site construction.

During the plant's shakedown period, June–December 1985, it had the usual new-system failures and problems. There were failures of the turbine inlet screen, of the seals on the 0.76-m-diam (30-in-diam) main hydrocarbon control and stop valves, and of the seal assemblies on the four hydrocarbon condensate pumps, and there were high vibration levels on the hydrocarbon booster pumps. After the inlet screen failure, the turbine was opened and the rotor returned to the manufacturer (Elliott Turbines) for inspection.

The project was formally dedicated on December 6, 1985, thus marking the end of the startup and shakedown period and the beginning of the operating and testing phase.

Table 1
HEBER PLANT OPERATING STATISTICS

	1985 June–December	1986 January–June	Total Since Synchronization*
Gross generation (MWh)	17,869	55,601	73,470
Net generation (MWh)	4,071	14,831	18,902
On-line (h)	1,478	4,055	5,533
On-line (%)	28.7	93.3	58.4
Brine production (10^6 lb)	4,946	10,372	15,318
Heat transferred (10^9 Btu)	748	2,218	2,966

*The plant was synchronized with IID's 34.5-kV system on June 14, 1985.

Plant operation and testing

Since going on-line on December 8, 1985, the Heber plant has established an excellent operating record. Table 1 summarizes the first year's operating statistics. Also in December, a three-month maximum brine-flow test was started to obtain reservoir performance data that were needed to support reservoir modeling studies; the reservoir studies, in turn, were needed in locating the next production and injection wells. This flow test also allowed a demonstration of the power plant's operating capability.

The plant is designed to generate rated output with inlet brine temperatures ranging from 182°C down to 170°C (360–338°F). The temperature of the brine delivered to the plant during the first year was slightly above the design temperature, ranging from 184.4°C down to 182.7°C (364–361°F).

At Heber, the brine system is designed to pressurize and return the cooled brine to Chevron at a nominal temperature of 71°C (160°F) and at a pressure of 2.8 MPa (400 psig) for injection back into the reservoir. However, because of the tightness of the reservoir, the injection pressures required during the first year have ranged from 3.3 MPa to over 4.4 MPa (480–640 psig), depending on the brine flow level. The plant's four brine injection pumps can operate at these higher pressures, but the effect of this change on plant operation is being examined carefully.

During the plant's first annual inspection, conducted in July 1986, some of the equipment was opened and checked for scaling, corrosion, and erosion. Two of the brine-hydrocarbon heat exchangers and two of the brine return pumps were included in this inspection; no significant problems were found, however.

SDG&E worked with representatives from EPRI, DOE, and some of the utility participants to develop an intensive test and demonstration program to document the performance of the major equipment, systems, and total plant. To demonstrate the technology's commercial potential, a number of production runs are also scheduled. Three major types of tests are included.

- Acceptance tests, to ensure compliance with equipment procurement requirements
- Baseline tests, to establish a performance baseline for each major piece of equipment over a broad operating range
- Long-term tests, which are periodic tests, to measure and identify any change in equipment or system performance

About 70% of the equipment tests were completed during the first year of testing. Emphasis was on completing all the acceptance and baseline tests on the plant's major pumps: eight hydrocarbon pumps, two cooling-water pumps, and four brine-return pumps. Except when prevented by brine supply or equipment problems, all the baseline tests were conducted, and the long-term tests are under way. The long-term pump test results show no significant performance degradation over this initial operating period. Also, a number of tests of cooling-tower performance and sensitivity were completed. Testing of the eight brine-hydrocarbon heat exchangers and two hydrocarbon condensers has not been completed. The 70-MW turbine generator tests are not scheduled until full brine flow is available.

Because the brine flow rate has not yet reached 100%, there is excess capacity available in the heat exchangers, condensers, and cooling tower. As a result, overall plant performance is about 10–15% above the design level at partial load.

The cost of the Heber project—design, construction, operation and testing (early 1980 through May 1988)—was estimated in 1982 to be $188.5 million; this included funds to purchase the geothermal heat from Chevron and to cover Chevron's operation and maintenance expenses. Although the costs of the design and construction phases were higher than originally estimated, the total project cost is expected to be below the 1982 estimate because the price of the geothermal heat is tied to a number of oil industry index values, and the recent oil price reductions have lowered that price. Detailed costs for the design and construction phases will be released later this year.

In April of this year, SDG&E won *Power Magazine*'s 1986 Electric Utility Energy Conservation award for the Heber project. The award is made annually to a utility ". . . growing toward energy independence by making use of renewable and indigenous resources. . . ." *Project Manager: J. E. Bigger*

PROGRESS IN WIND POWER

Over the past five years independent power producers, particularly those in California, have dramatically expanded their use of small wind turbines in the commercial-scale generation of electricity. In California the number of operating wind turbines increased from 144 in 1981 to more than 13,000 at the end of 1985. In the process of this commercialization of wind turbine technology, several advantages of the smaller turbines have been demonstrated—for example, design simplicity, relative ease of installation and repair, and higher reliability. The status of the commercial utilization of wind power through 1984 was surveyed in an EPRI report (AP-3963) that is now in the process of being brought up to date.

The wind turbines brought on-line during the recent expansion of wind-power-generated electricity comprise a variety of engineering approaches and designs, and as a result there is a concomitant variation in their basic engineering integrity and performance. Nevertheless, several promising trends can be identified.

In general, prices have dropped sharply while reliability has been significantly improved. Moreover, operation and maintenance costs are also coming down. During this period of improving reliability and prices, the ratings of installed turbines have moved up fairly steadily from an average of about 50 kW in 1981 to about 100 kW in 1985. And these rating increases have been achieved without sacrificing design simplicity. It might be advantageous to push the ratings even higher, but further increases are not essential from an economic standpoint. The primary technical uncertainty that now remains is the operating life of major system components over the long term.

Leading developers of wind power stations are beginning to recognize the benefits that can derive from deploying their turbines in more fully integrated wind power stations—benefits like centralized monitoring, control, and data acquisition. Consolidation of the wind power industry, brought on by increased competition and changes in tax incentives, also indicates a smaller industry in the future, but one made up of more-stable and more-capable participants.

The aggregate rating of wind turbines installed in the United States is estimated to be about 1.1 GW. However, caution must be exercised in interpreting this number. As yet, there are no standards for rating wind turbines. Turbine output is a function of wind speed: the rating is merely a point on the power-versus-wind-speed curve. And there is no consistency in the way turbine manufacturers select the rating point. Further, a turbine's actual output varies, above and below whatever point a manufacturer calls its rating, as the wind speed fluctuates up and down. Clearly, there is need for a standard on wind turbine rating practices.

Recent experience

The availability of individual wind turbine units in leading commercial wind power stations has been steady at about 0.95 over the last two years. This high availability is expected to continue as more operating time accrues, barring any major unforeseen component wear-out or fatigue-related structural problems. However, the success of small-wind-turbine technology does not hinge on a precise understanding of fatigue life. Ultimately, the fatigue life determines the interval between drivetrain overhauls, which in turn affects operation and maintenance costs. It is not, however, expected to be a showstopper for use of the technology in areas with sufficiently attractive wind regimes.

Operation and maintenance costs have continued to fall and appear to be approaching about 1¢/kWh for large wind power stations. Installed costs for wind power stations have fallen dramatically and are now ranging from $1200 to $1900/kW. These costs are still dropping, but at an increasingly slower rate. Capacity factors are trending to 0.24–0.34 in California, an impressive range considering the variability of the wind. Energy production by wind power stations in California has moved up from about 50 GWh in 1983 to about 660 GWh in 1985. In general, wind power stations using the smaller machines look very attractive as a future utility generation option.

In contrast to the experience with small wind turbines, the experimental multimegawatt wind turbines continue to exhibit little improvement in reliability and poor availabilities because of their size, complexity, and demanding logistic requirements. The first experimental prototypes, which appeared in about 1981, revealed serious problems, particularly those related to the understanding of costs and cyclic loads and their origins. Long downtimes associated with failures slowed technical progress. Questions raised about the practicality of the big machines and the size of the market for them made it doubtful that the production volumes on which early cost estimates were based would ever be reached.

The significant risks that surfaced, along with premature attempts at commercialization, made it difficult to justify the additional long-term research commitments that would have been required to continue development of multimegawatt machines. In general, the challenge would have been to achieve simultaneous gains in structural margins and reductions in weight, complexity, and cost through new generations of prototypes. The prevailing viewpoint is that it is more cost-effective to develop wind turbine technology from the bottom up than from the top down. In other words, to start with the small machines and then go on to larger ones instead of trying to streamline the multimegawatt machines. Also, by starting with small machines, an industry would be established during the developmental phase that could not be built during prolonged development of the multimegawatt machines. When turbine sizes finally level off on the basis of costs and logistics, it is expected that the range will be well below the excessively large turbines (e.g., 300-ft [90-m] rotors) associated with the federal government's program (e.g., the MOD-2 machine).

Small wind turbines have been developed to the point that the utility industry can factor wind power into its long-range generation expansion plans and take the early steps necessary to prepare for wind power. Those early steps include intensive resource measurement programs and pilot wind power stations. Although some refinements, such as variable-speed generation through power electronic control, will be forthcoming in future years, the turbines are already sufficiently attractive for use by utilities with suitable wind resources. Because of the inherent modularity of wind power stations, a utility can build a wind power station incrementally and use the best turbines available at the time any given increment is built. (Additional information on recent experience with wind power can be obtained in AP-4638 and AP-4639.)

Prospects for utility use of wind power

There are a number of areas throughout the United States with wind conditions favorable for generating electricity. The largest such area is in the Great Plains. The areas of California in which wind turbines have been installed contain a very small portion of the overall national wind resource. Determining the full potential within areas that have not been developed will require quantification of localized wind variations, determination of site accessibility, and identification of institutional restrictions on wind power development. The prospects and requirements for the geographic expansion of wind power installations were examined in a recent EPRI workshop (AP-4794).

In addition to the extensive use of wind power by private developers in California, a few utilities in other areas of the country have begun to develop small-wind-turbine power projects. This utility use of wind power is likely to show gradual growth over the next 15 years irrespective of advances in wind power technology. However, there are some key areas in which potential advancements could significantly enhance the attractiveness of wind power to the utility industry.

Most important are applications of power electronic technology to wind turbine control and to wind power station control and protection. For the turbine, the goal is to develop a utility-grade machine incorporating variable-speed generation through power electronic control. In general terms, the research objectives are to quantify the probable benefits of power electronic control and thereby establish cost and performance targets; to develop the requisite power electronics through suitable laboratory work; and to apply the power electronics to wind turbines. Given suitable design variations, the advanced power electronics used for wind turbines may also have other applications.

The following are thought to be the principal advantages of power electronic–controlled variable-speed generation.

- Better compatibility of wind power and the utility system. The wind turbines could be regulated and could handle wind variations with less cycling stress on thermal units. Suitably designed power electronics are also expected to provide a power factor correction capability. Care must be taken so that the variable-speed system does not become a source of harmonics.

- Greater operational flexibility. This would provide more-efficient start-stop sequences, a modest widening of the operating wind speed range, and a lower duty cycle on pitch controllers (where applicable).

- Improved adaptability of turbines to sites. Wind turbines are now changed mechanically to adapt them for use over a range of site-to-site wind conditions—airfoils, blade lengths, and tower heights are varied. The power electronic system provides a means of making finer adjustments that can further help offset site-to-site and even intrasite differences in wind characteristics.

- Improved dynamics. Torsional damping and structural load alleviation provided by power electronics may reduce component wear and/or weight. Structural resonances can be bypassed through electronic control.

- Improved energy capture.

Variable-speed generation (and all other potential advances in wind turbine technology) improve the cost-effectiveness of wind turbines across the full range of usable wind speeds. Obviously, no advances can make wind turbines work in low winds.

The process of developing advanced power electronic devices for station protection and control would parallel that described earlier for turbine control. Because wind power stations are highly modular, they require extensive control and power collection networks. Hence, it is desirable to have low-cost, low-power control and protection devices to integrate the turbines into reliable, easily operable, and cost-effective wind power stations. The development of these devices would require the same definition, laboratory work, and field-test sequence as the turbine controllers. Both the turbine and station applications of power electronics are ways of making wind power more fully compatible with utility industry needs. (For additional information, refer to AP-4261 and AP-4590.) *Project Manager: Frank Goodman*

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Vice President

BOILER RELIABILITY

Statistical data collected on coal-fired units 400 MW and larger by the North American Electric Reliability Council (NERC) for 1975–1984 show that boilers and their related auxiliaries had an average equivalent availability of about 80%. This report describes EPRI's current and planned research to develop technologies and solutions for reducing availability loss due to boiler pressure part failures, cycle chemistry, maintenance, and coal quality effects.

Boiler tube failures

Boiler tube failures (BTFs) are the leading cause of availability loss in U.S. power plants. The equivalent availability loss attributable to boiler tubes is over 6%. Despite a significant industry effort to prevent BTFs, more than 40,000 have been recorded in the past decade. A large percentage of these are repeat tube failures caused by the same mechanism. Failures have occurred in all boiler areas: economizers, waterwalls, superheaters, and reheaters. More than 80% of BTFs force a shutdown, and a typical outage lasting three days can cost a utility $750,000 for replacement power.

As part of a multifaceted approach to the problem, EPRI has developed a manual for power plant personnel to use in investigating BTF causes (EPRI CS-3945). Determining the correct failure mechanism and root cause in each case is of paramount importance. Proper corrective action can then be taken to alleviate the root cause, adopt monitoring procedures, and thus eliminate repeat failures.

The BTF manual categorizes 22 currently known failure mechanisms. Color photographs show examples of each mechanism, and typical failure locations are illustrated. The manual also discusses probable root causes and ways to verify them. Most important, it describes in detail the required corrective actions for preventing repeat failures and providing permanent solutions. The manual is now being used in most U.S. power plants, and a follow-on project is under way to demonstrate the methodology at 10 host utility systems and to prepare additional training materials for all levels of utility personnel (RP1890-7). Ultimately this structured and multidisciplinary approach, when coupled with the introduction of a root cause statistical data base, should achieve a marked reduction in BTFs.

Of the 22 failure mechanisms described in the manual, only two require further R&D to determine the root cause: corrosion fatigue failures that begin on the water side of waterwall and economizer tubing and circumferential waterwall cracking that begins on the fire-side surfaces of supercritical units. Two other failure mechanisms, fire-side corrosion and fly ash erosion, require further work to demonstrate the efficacy of proposed permanent solutions.

Corrosion fatigue failures are the leading single cause of availability loss in fossil fuel plants and will have important ramifications for the many U.S. utilities switching these plants from baseload operation to cycling or two-shifting. Failures occur mainly where thermal expansion is restricted during transient conditions (e.g., startup). Typical failure locations are at pressure-nonpressure attachments.

A project is under way to determine the root cause of corrosion fatigue and to provide predictive techniques and solutions (RP1890-5). Specifically, it will delineate the conditions of stress and boiler water environment (dissolved oxygen and pH) that are necessary to avoid failure. The approach being taken combines detailed in-plant monitoring of four boilers, stress analysis, and laboratory corrosion fatigue characterization.

Supercritical waterwall cracking originates at the fire side of the tubes in the areas of highest heat flux; it usually takes several years to develop. A previous project (RP1265-12) identified the mechanism to be thermal fatigue in a corrosive environment. A subsequent survey of 56 supercritical boilers (RP1890-4) tried unsuccessfully to identify common features (and a root cause) in those units that showed cracking. In a follow-on project (RP1890-8), researchers will monitor such parameters as waterwall temperatures and strains in four boilers while varying operating conditions and feedwater chemistry. In this way they hope to determine the operating procedures or variables that cause waterwall temperatures to rise above normal design and operating levels.

BTFs due to fire-side corrosion and fly ash erosion have been addressed in RP2711-1. Ten utilities and the boiler manufacturers were surveyed to assess the importance of these mechanisms in overall availability; also, the state-of-the-art techniques being applied to the problems were evaluated. Fly ash erosion of superheater, reheater, and economizer tubing is a more serious problem than fire-side corrosion, although external corrosion of waterwalls appears to be increasing in importance. Currently the problems are being effectively managed by extensive maintenance and by such temporary measures as pad welding and the fitting of tube shields and baffles. Although proven, permanent solutions are available for most of the problems encountered, they are not being applied because installation costs are perceived to compare unfavorably with the costs of continued maintenance. Nevertheless, these mechanisms still cause several forced outages annually, and most are repeat failures.

Some permanent solutions for fly ash erosion and fire-side corrosion have been implemented by British and Canadian utilities, including the use of more-resistant alloys or cladding and the use of a cold-air-velocity monitoring technique that enables better location of preventive diffusing screens, baffles, and shields. The efficacy and cost-effectiveness of these techniques will be demonstrated at two U.S. utilities (RP2711-2).

As well as attempting to identify the root cause of each type of BTF and to provide permanent solutions, EPRI is investigating nondestructive evaluation techniques that offer the following advantages: rapid, accurate detection and sizing of boiler tube damage; minimum interference with normal maintenance and repair activities; high-volume coverage; and minimum operator interpretation.

Ultrasonic testing guidelines for assessing boiler tube damage have been assembled under RP1865-5. They describe techniques for determining wall thickness, cracking, pitting, and hydrogen damage and discuss surface preparation, personnel qualifications, available equipment, and associated costs. A computer code for analyzing ultrasonic testing data and determining optimal inspection intervals has also been developed. The inspection guidelines and the code will be demonstrated in five host utilities over the next three to five years.

In a comparative study of several advanced boiler tube inspection techniques (RP1865-1), infrared systems and electromagnetic acoustic transducers (EMATs) showed sufficient promise to warrant the development of prototype field devices. Infrared thermography has the potential for rapidly scanning large areas of tubing to find regions where there is a high likelihood of future tube leaks. RP1865-4 has investigated a procedure involving the rapid release of high-temperature steam into the waterwalls of a boiler; this transient condition makes possible the momentary detection of pitting, tube blockages, and wall wastage. Field trials at Boston Edison Co.'s Mystic station showed the technique to be sensitive to changes of 10% in wall thickness.

Traditional ultrasonic measurement of tube wall thickness requires grinding away the tube's corrosion layer. With the EMAT device, the electromagnetic wave travels through this layer and is absorbed directly into the tube wall. Field trials have been conducted at Pacific Gas and Electric Co.'s Pittsburg station.

Boiler water chemistry

Boiler water quality is a major factor in BTFs. Utilities are faced with a multitude of water and steam control limitations imposed by various standards groups and manufacturers. As part of a project on overall fossil fuel plant cycle chemistry (RP2712), EPRI has recently issued interim consensus guidelines (CS-4629). These provide a set of target values and action levels for critical sample points throughout the water-steam cycle for drum boilers using phosphate or all-volatile treatment and for once-through boilers using all-volatile treatment. The guidelines are applicable for baseload, cycling, and peaking operation. They will be verified and improved in a follow-on project (RP2712-2) in which six fossil fuel plants will be extensively monitored with state-of-the-art instrumentation and data logging. When implemented, the guidelines are expected to bring significant benefits to utilities at a moderate cost, as has been the case in countries where similar guidelines have been introduced.

Boiler maintenance

Data from NERC's Generating Availability Data System for 1975–1984 show that in coal-fired units 400 MW or larger, about 10% of boiler availability is lost annually because of scheduled outages for repairs and/or preventive maintenance. Through the use of current state-of-the-art techniques and the development of advanced maintenance technology, a 20% reduction in this scheduled outage time—with a corresponding boiler availability improvement of 2%—seems feasible. Further availability improvement could be realized if these same techniques were applied during forced outages as well.

In RP2504-1 the state of the art of maintenance technology was defined, and areas requiring further development were delineated. Eighteen major activities associated with the maintenance and repair of boiler tubes, burners, hoppers, sootblowers, pulverizers, draft system expansion joints, and air heaters were evaluated, and detailed descriptions of the best current technologies were prepared for use by utility personnel. The preventive maintenance activities involved in annual boiler inspections and the chemical cleaning of heat transfer surfaces were also addressed.

The second phase of this effort, to begin in 1987, will develop advanced technology—including welding and scaffolding guidelines, quality control procedures, and tools—for reducing the frequency and duration of major maintenance activities.

Coal quality

Coal quality affects the design and operation not only of boiler components but of almost all plant equipment, from the coal handling system to the stack. A recent four-volume EPRI report (CS-4283) reviews the current procedures and correlations for evaluating coal quality effects. In a follow-on project (RP-2256-2), researchers are developing a state-of-the-art coal quality impact model (CQIM). This comprehensive model will account for the effects of a change in coal quality on all relevant plant equipment and calculate the net differential cost of electricity generation. The first version will be tested and verified at utility sites in early 1987; the model will then be upgraded as improved correlations become available.

In another project (RP2425), EPRI is evaluating the benefits of coal cleaning for plant performance by testing run-of-mine and cleaned coals in a pilot-scale combustor (4 million Btu/h). Twenty-ton samples of the coals are tested for pulverization, slagging, fouling, erosion, and electrostatic precipitation. Three coals have already been tested: an Illinois No. 6 bituminous, a Kentucky No. 9 bituminous, and a Texas lignite. The pilot-scale results are being scaled up to predict performance in a full-size unit.

EPRI is also addressing slagging and fouling through fundamental research on mineral matter transformation during combustion and on ash deposition processes (RP2425-3). In RP-1891-1 data collected from 130 units are being analyzed to evaluate the relative merits of the many indexes used to predict slagging and fouling in operating boilers. A major conclusion of this study is that boiler design and operating variables must be considered if accurate predictions are to be made.

EPRI is developing guidelines for systematically measuring the performance of various power plant components affected by coal quality (RP1891-3). At least four host utilities will be involved in demonstrating these guidelines, and EPRI will use the results in validating both CQIM and the full-scale performance predictions being developed in RP2425.

Remaining-life assessment

It is important not only to determine the root causes of failure behind boiler unavailability but also to assess the remaining useful life of components under defined operating conditions. This aspect of the reliability work is of major importance to plant life extension, for which EPRI has assembled generic strategy guidelines (RP2596).

The overall objective of EPRI's effort in boiler life assessment is to develop and validate nondestructive methods that represent significant improvements over current methods for estimating the remaining life of boiler pressure parts operating at elevated temperatures. RP2253-1 has promoted the widespread successful use of several techniques, including the replica technique and the miniature specimen technique. RP2253-10 will integrate all the currently known life assessment techniques for headers, tubing, and steam pipes into a generic, computer-oriented methodology.

Other related research in the area of boiler reliability is focusing on the major auxiliaries. Under RP1883-1 researchers have recently completed investigations into the root causes of pulverizer fires and explosions. Improved materials used in pulverizer grinding and pneumatic conveying systems have been assessed for abrasion (RP1883-2) and erosion (RP1883-5). Investigations of draft fans under RP1649 have addressed fan foundations, erosion protection, test procedures, root cause failure analysis, and the development of design guidelines.

In summary, the serious financial impact of boiler availability losses on utility resources can best be reduced through a combination of several factors: a proper understanding of root causes, the development of permanent solutions to counteract root causes, the development of root cause data bases (particularly for BTFs), the application of preventive and advanced maintenance techniques, and a thorough understanding of coal quality effects. *Project Manager: R. B. Dooley*

INTEGRATED POWER PLANT WATER MANAGEMENT

During the last decade, many power plants in the western United States have overcome a scarcity of water resources and met environmental regulations for aqueous discharges by recycling and reusing water. These zero-discharge plants have pioneered approaches in the design and operation of integrated water management systems. EPRI is now working to introduce and apply these practices to power plants across the country that face increasing competition for freshwater resources and tightening discharge regulations. A major focus of EPRI's activities is to provide the utility industry with guidelines and supporting computer codes that help simplify the inherently complex task of integrated water management.

Traditionally, water management in power plants has involved only boiler water chemistry control; with the advent of integrated water management, however, the chemistry and flow of all process streams have become important. For example, the single largest demand for makeup water comes from the cooling system, followed by the flue gas desulfurization (FGD) and ash handling systems. From an overall power plant perspective, then, the balance-of-plant systems are the primary focus of integrated water management.

When considering so many systems, it is critical to recognize the differences in process stream chemistries and flows and in process system requirements. For example, to avoid scaling and corrosion, the cooling system usually requires high-quality makeup water and regular monitoring. On the other hand, makeup water requirements for the ash and FGD systems may not be so rigid. In bottom and fly ash systems, low-quality water has been used for ash sluice makeup, bottom ash cooling, fly ash wetting, and dust suppression. In wet lime/limestone FGD systems, low-quality water has been used for reagent dilution and mist eliminator washing. Indeed, in some instances cooling-tower blowdown can be used to offset fresh makeup water needs in ash and FGD systems.

The basic premise of integrated power plant water management is that process streams are segregated according to water quality, then cascaded from system to system (integrated) according to demand for water quality. Because plant designs, raw water quality, and other conditions vary across the United States, the possible recycle/reuse options are very site- and situation-specific. As a consequence, EPRI has sponsored considerable laboratory- and pilot-scale research toward understanding and refining this approach.

Water management guidelines

A primary problem in implementing integrated water management is the lack of a method that allows system operation to be changed to accommodate changing process water chemistry. In many cases plant personnel have been unable to take appropriate corrective action because a thorough understanding of the complicated, interrelated system flows and chemistries was not available.

Since 1981 EPRI has been working to develop and demonstrate a simple methodology for determining water flow and mass (salt) balances in all plant processes. The basic approach involves (1) preparing a total plant system flow diagram, (2) identifying locations for flow meters and stream sampling, (3) collecting selected stream flow and composition data for a specified period of time, and (4) evaluating the data by using flow and mass balances to determine inconsistencies and to identify possible improvements.

The methodology was first demonstrated at the Colorado-Ute Electric Association's Hayden station (a zero-discharge plant), with very encouraging results (EPRI CS-3845). According to the water balances, the cooling-system blowdown was 10–20% above the design flow rate. However, the cooling-water chemistry conditions at Hayden would allow the blowdown rate to be reduced by 50% and still be within accepted operating guidelines (which are presented in CS-2276). This blowdown reduction, combined with other operating changes, could save the station $160,000 a year in wastewater treatment operating costs.

Although successful, this demonstration required a mainframe computer and specially written computer codes for managing the data and performing calculations. Thus it seemed unlikely that this methodology would be widely accepted and used. But recent advances in microcomputers and associated software provide an easier and faster means of applying the water balance approach.

A second demonstration, conducted at the Public Service Co. of New Mexico's San Juan station, evaluated the use of an IBM PC and commercial spreadsheet and data base management software (e.g., Symphony and dBase II) to perform plant flow and mass balances. As before, an overall plant flowsheet was prepared first. Then it was translated into a link-node diagram as the basis for preparing a spreadsheet on the IBM PC. This process is illustrated in Figure 1.

For six weeks the plant staff collected and input data on the flow and composition of various streams to characterize the station's water use. The personal computer and prepackaged software proved especially suitable for calculating power plant flow and mass balances. Although it is still too early to estimate the economic benefit of this demonstration for the plant, the staff found they could quantify flow rates that were impractical to measure, identify malfunctioning instruments and define maintenance schedules, detect discrepancies in subsystem water balances, and estimate the potential water balance impacts of various changes in process conditions.

In addition, plant personnel used the software to develop a program for monitoring and predicting the levels of solids and liquids in the station's evaporation ponds. The results of this demonstration are summarized in a two-volume report (CS-4482). Volume 1 provides guidelines for developing and using microcomputer-based flow and mass balances for a water management system; Volume 2 discusses the San Juan station case study.

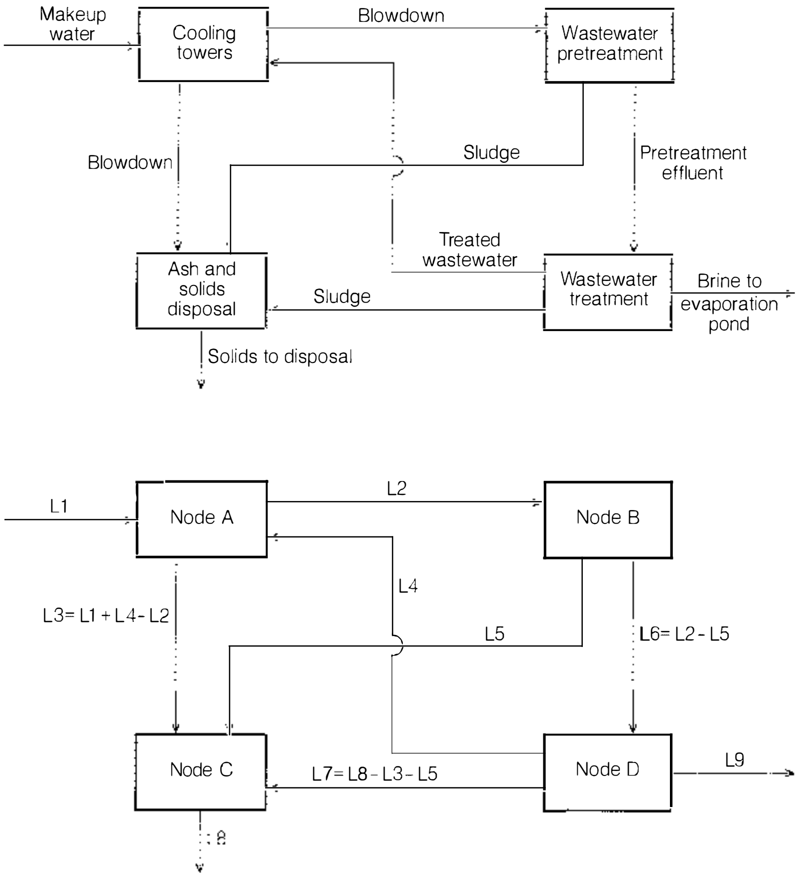
In a related project (RP2114-6), EPRI is developing instrumentation guidelines for water management systems. These guidelines will cover important considerations for specifying, selecting, calibrating, installing, and maintaining the instrumentation needed for various water management applications, such as monitoring flow, pH, temperature, and specific ions. Publication is scheduled for early 1987.

Computer codes

As a follow-on to the San Juan case study, EPRI is evaluating other opportunities for using microcomputers to simplify the design and operation of plant water management systems. In RP2114-5 microcomputers and commercial software will be used to develop a standard approach, with a reliable supporting data base, for conducting technical and economic comparisons of water management options. Unlike the guidelines for flow and mass balances, these guidelines will take the form of an actual computer code or template for use in conjunction with FRAMEWORK II and dBase III.

The menu-driven code will enable users to create a site-specific water balance for all or part of a plant's water management system and then to evaluate the technical and economic impact of variations in the system's design and operation. Through a question-and-answer format, the user can customize the

Figure 1 Using flow and mass balances to improve plant water management begins with the preparation of a process flow diagram (top). On the basis of flow meter locations, a link-node diagram is then developed (middle); this shows the flows (designated by *L*) as measured or, in some cases, as calculated—here, for example, *L3, L6,* and *L7*. Finally, a microcomputer spreadsheet program (bottom) is used for data evaluation and interpretation.



	Systems				Off-site		
	To cooling towers (A)	To waste-water pre-treatment (B)	To ash and solids disposal (C)	To waste-water treat-ment (D)	To disposal	To evapora-tion pond	Sum of flows
From cooling towers (A)		Blow-down (L2)	Blow-down (L3)				L2 + L3
From waste-water pre-treatment (B)			Sludge (L5)	Pretreat-ment efflu-ent (L6)			L5+ L6
From ash and solids disposal (C)					Solids (L8)		L8
From wastewater treatment (D)	Treated wastewater (L4)		Sludge (L7)			Brine (L9)	L4+ L7 + L9
From off-site	Makeup water (L1)						L1
Sum of flows	L1 + L4	L2	L3 + L5+ L7	L6	L8 + L9		

analyses by accessing the associated data bases for input or by providing plant-specific data. The code has the flexibility to perform sensitivity studies, pursue new evaluations for related options, or save the existing analyses for future reference. A prerelease version will be ready for distribution to member utilities on a demonstration basis in 1987.

EPRI is also developing microcomputer codes for specific water management systems. Under RP1261-13 an IBM PC code is being developed to simulate lime-soda softening systems. Previous EPRI studies (CS-4040, CS-4076, CS-4212) have demonstrated that softeners in a makeup or sidestream application can remove calcium and silica from recirculated-cooling-water systems to prevent condenser scaling. However, it has been difficult to design and operate softening systems properly because of the complex aqueous chemistry involved. A prerelease version of the softener code is available for utility demonstration.

In a related effort, EPRI's mainframe computer code for simulating the aqueous chemistry of cooling-water systems (DRIVER) has been converted for use on the IBM PC and is available for prerelease utility demonstration. This code is useful for determining the scaling potential of recirculated cooling water and for estimating the acid addition necessary to maintain a given system pH.

As these computer codes proceed through prerelease demonstration and become available as production-grade codes, EPRI will investigate the possibility of establishing users groups. Such groups will provide a forum for EPRI and the industry to discuss code applications and for group members to share experiences, identify problems, and make suggestions about enhancing future versions or developing entirely new codes.

Outlook

The attendance at an EPRI symposium last February on advances in fossil fuel plant water management indicates that the concept of integrated water management is gaining national acceptance, even in areas traditionally considered water-rich. Much of this interest in water management is the result of new environmental restrictions on discharges, particularly for trace metals and potential hazardous substances. The most effective approach for meeting these new limits is to reduce the total plant discharge through knowledgeable recycling and reuse of process water streams. EPRI's role in developing and demonstrating water management guidelines and computer codes will help the utility industry address these new environmental issues in a timely and cost-effective manner. *Project Manager: Wayne C. Micheletti*

R&D Status Report
ELECTRICAL SYSTEMS DIVISION

Narain G. Hingorani, Vice President

TRANSMISSION SUBSTATIONS

Evaluation of electronic current transducer

General Electric Co. developed and tested the electronic current transducer (ECT) for EPRI in 1976–1978 (EPRI final report EL-1343, February 1980). The instrument is a freestanding bipolar electronic current transducer for use on a 400-kV line having a nominal line current of 2000 A. A single unit was built for test and field evaluation, using state-of-the art techniques and components available in the mid 1970s. Fabrication was consistent with laboratory and commercial practices but not finalized for production. The ECT was fully tested and calibrated when delivered to EPRI for test and evaluation on the HVDC system at Sylmar.

The ECT was installed at Sylmar in December 1978 and has been operating almost continuously ever since. Initially, it was mounted inside the valve hall and connected in series with the 400-kV bus where the bus meets a large HV bushing, which extends through the building wall to the transformer yard. Here, the ECT was subjected to the full voltage stress of the line bus. However, being inside the building, it was not subjected to the outside environment and weather conditions.

In November 1982 the ECT was moved outdoors to a site in the pole-3 transformer yard. It was connected in series with the neutral feeder bus near ground potential. This new location provided an opportunity to operate the ECT in an environment in which it would be subjected to strong sunlight, wind, and rain, and a wider range of ambient temperatures than it had suffered in the valve hall.

During more than six years of almost continuous operation, the ECT has performed well and has satisfactorily met the overall expectations and purposes of the project. Some problems and component failures have occurred in this period but not an unusual number for a state-of-the-art project of this complexity. Other favorable points about ECT performance and operation can be noted.

- The ECT's low dc drift required that the channels be checked and possibly recalibrated no more than once per year.

- The cascade transformer link and voltage grading network proved to be a reliable way of conveying power to the line. They also provide power when the dc line is down, which means the ECT is ready to operate at any time. The overall high-voltage integrity of the ECT system was demonstrated.

- There were no signs of moisture damage or poor seals from long-term outside exposure. The line shunt demonstrated continued reliability, whether the ECT was installed indoors or outdoors.

- The data communications system has remained stable and reliable over the six years. Channel A has all original components; channel B has required a change of two components. The optical fiber portion of the data communication link has remained reliable during the six years.

- The original LED transmitters are still in use. At an 8-kHz clock rate, each LED has experienced approximately 10 trillion pulses to date.

Utilities interested in arranging to test or install such a device should contact the EPRI project manager. *Project Manager: Harshad Mehta*

Pyrolysis and combustion of PCB substitutes

A number of chemicals have been and are being considered for use as substitutes for polychlorinated biphenyls (PCBs) in electrical applications. Although all have been tested for acceptable dielectric, heat transfer, and flammability properties, few have been extensively analyzed for combustion by-products.

PCBs were not restricted for problems with their dielectric properties or heat transfer capabilities but, rather, for suspected toxicological properties that were not considered when PCBs were first commercially produced. These toxicological properties are attributed not only to the PCBs themselves but also to the presence of various chlorinated aromatics in the by-products of PCB/askarel fires. It is thus necessary to examine the chemical behavior of proposed PCB substitutes to identify the potential for similar problems.

Two EPRI contracts have addressed the question of pyrolysis and combustion products of some of these substitute materials. SCS Engineers searched the literature (RP2028-12); Westinghouse Electric Corp. tested products in the laboratory (RP2028-11).

Until very recently, a major concern in any fire or explosion episode was fire fighter safety. As a result, tests have focused almost exclusively on major gaseous combustion products, such as carbon monoxide, hydrogen cyanide, oxides of nitrogen and sulfur, hydrogen chloride, and so forth. These combustion products are life-threatening, and they are generally the simplest to detect and measure.

However, several PCB incidents have made evident that soot deposits with trace amounts of toxic products are more of a problem than are vapors. Products of incomplete combustion (PICs) are produced in such small amounts that vapor emissions dispersed into the atmosphere rapidly reach inconsequential levels. These same PICs may concentrate in soot, however, and soot provides a reservoir for continued emissions or exposure long after a fire has been extinguished and the gases dispersed. The purpose of the SCS Engineers project was to review state-of-the-art literature and determine what is known regarding the chemical and toxicological nature of the combustion by-products of various PCB substitutes.

The review covered literature on potential substitutes in both transformers and capacitors: liquids such as phthalate esters, benzyl neocaprate, silicone, chlorobenzene, methylated diphenylethane, phenylxylylethane, alkylbiphenyls, paraffinic hydrocarbons, and tetrachloroethylene; gases such as chlorofluorocarbons (low-boiling-point liquids) and sulfur hexafluoride; and solids such as epoxies and polyvinyl chloride.

These materials did not exist in the crisis situation of PCB. As a result, with a very few exceptions, comparable research has not been conducted into their PICs. As noted above, existing data tend to focus on the macrocombustion products present in the vapor state rather than trace PICs in the soot. Consequently, relatively few data exist on trace PICs comparable to those on dioxins or dibenzofurans. These types of by-products simply have not been identified and studied in most cases.

The laboratory investigation was designed to identify the products of incomplete combustion of five types of dielectric fluids commonly used in transformers as alternatives to askarels—tetrachloroethylene, trichlorotrifluoroethane, polydimethylsiloxane (silicone fluid), mineral oil, and a high-temperature hydrocarbon.

Researchers began the investigation of these fluids by studying their thermodynamic equilibrium over a range of temperatures and pressures. The experimental program was carried out in two separate studies. One involved heating the fluids from room temperature to 1000°C, and another injected them into a furnace that was preheated to 1000°C. The air level in each chamber was chosen to provide 70% or 30% of the oxygen required for total combustion.

None of the tests produced detectable chlorinated or polycyclic aromatic hydrocarbon particulates. Detectable quantities of chlorine and hydrogen chloride were produced from tetrachloroethylene, as well as a small amount of dichloroacetylene. Trichlorotrifluoroethane produced a number of fluorocarbon compounds as well as hydrogen fluoride. Silicone fluids produced substantial quantities of a solid material, believed to be silicon dioxide and, like the two hydrocarbon fluids, produced several combustible hydrocarbon gases, as well as carbon dioxide and carbon monoxide. *Project Manager: Gilbert Addis*

Oil pump performance evaluation

The pumps that are used to circulate oil for cooling large power transformers generate static charges. Pumps generate more static charge than do other parts of transformer cooling circuits because static charge generation is a function of oil velocity and oil velocity is highest in pumps.

In this project McGraw-Edison Co. is using acoustic detection and frequency analysis techniques to identify the dissipation of static charge (partial discharge) in the cooling circuit both at and downstream from the pump (RP426-2). The techniques effectively discriminate between the sound of partial discharge and other pump noises (bearings, cavitation). Among other instruments, McGraw-Edison's partial discharge detector (PDD), a portable, easy-to-use instrument developed for a previous EPRI contract, is being applied. The battery-powered instrument uses a piezoelectric transducer, amplifier, and filter to detect the small mechanical shockwaves caused by partial discharges.

Several different pumps are being examined. Although no conclusions have been drawn yet, researchers have made some interesting observations.

- The charging/discharging tendency of oil relative to moisture content is being confirmed.
- Flow rates definitely affect charge generation.
- The relaxation of charges generated by oil pump operation can be detected with acoustic emission techniques.
- Pump bearing material appears to be an important factor.

The work is being done at J. W. Harley Pump Works, Inc., where there is a test stand suitable for evaluating oil pump performance. *Project Manager: Dennis Johnson*

POWER SYSTEM PLANNING AND OPERATIONS

Reliability modeling of interconnected systems

Most utilities operate as members of an interconnection or pool; hence, they need models that explicitly recognize the transfer capabilities and transmission limitations, which was the subject of this project (RP1534-2). Generating unit and system operating characteristics significantly influence generation system reliability. The effect of intersystem transmission limitations and the correlation of unit duty cycles between areas adds a new dimension to the reliability calculation methods. This project had the following objectives.

- Identify the unit and system operating characteristics that influence generation system reliability of interconnected systems
- Extend the single-area analytic model, OPCON, for multiarea analysis (up to 10 areas)
- Expand the single-area Monte Carlo simulation model to three areas to serve as a benchmark for the analytic model

A new analytic model, OPRINS, was developed that effectively used the features of the OPCON model developed in RP1534-1 and the network simulation model, REMAIN, developed at Pacific Gas and Electric Co. The three-area Monte Carlo simulation model, GENESIS 2.0, was used as a benchmark to validate OPRINS. The new models were tested on EPRI synthetic utility systems.

Accurate modeling of these operating factors will help utilities evaluate alternative operations policies and better coordinate the power transfers with neighboring utilities. This project demonstrated OPRINS usefulness for such applications. The model incorporates fundamentally sound analytic procedures of system operation and practical considerations of interconnections. Using this analytic tool, utilities can improve their generation system reliability and evaluate the benefits of interconnections. *Project Manager: Neal Balu*

UNDERGROUND TRANSMISSION

Pipe-type cable joint restraints

Pipe-type cables are manufactured in lengths of 2500–3500 ft (760–1070 m) for installation in steel pipes. These lengths of cable are spliced together in manholes and the splices are enclosed in large, steel joint casings. The daily loading changes cause a continual lengthwise expansion and contraction of the cables. For the most part, the expansion is accommodated by the undulations in the cable and at the bends in the pipe system. The expansion phenomenon exerts a force on the cable that is referred to as thermomechanical bending (TMB). Typically, a transmission cable will undergo one heat-up/cooldown period per day (i.e., a daily load cycle) and will therefore see one TMB episode per day. Required reliability for transmission circuits dictates that cables must accommodate TMB without damage during their expected lifetimes.

RP7873 is addressing the reliability issue on cable subject to TMB within the pipe. However, potential problems may occur if TMB is allowed to occur at the splice within its casing, where the casing diameter is larger than the adjacent pipe. The result could be severe damage from overbending, which causes the insulating tape on the splice to separate. To assess this situation EPRI funded RP7894 with Pirelli Cable Corp. Public Service Electric and Gas Co. (PSE&G), whose engineers developed a splice restraint device, was a subcontractor.

Users have always restrained joints with a somewhat rigid splice within the joint casing. However, certain splice casing designs and restraint schemes are inadequate. The solution, therefore, became one of designing and testing joint restraint concepts that ideally could be retrofit to existing pipe-type cable joints. The following two general conceptual approaches have evolved, each with numerous variations.

- Restrain the splice assembly to prevent all radial motion but allow some longitudinal motion within the joint casing
- Restrain the splice assembly and fix it within

its joint casing, allowing no radial or longitudinal motion

The first approach impresses only modest mechanical forces on the splice assembly because most of the cable expansion is accommodated by the longitudinal motion of the cable itself. The risk is that in a real field situation, the longitudinal motion may be greater than the design value and something has to give. The second approach eliminates splice movement entirely but impresses high mechanical forces on the joint restraint assembly. The risk is that even small amounts of slippage or motion may result in tape separation and electrical distress.

Project results to date have been encouraging, but mixed. The PSE&G–designed restraint device was tested on both crepe-paper- and hard-paper-insulated 345-kV joints and performed extremely well (*EPRI Journal,* October 1983, p. 46). The design fits into the second approach, and it has been installed commercially. A second joint restraint design fitting approach 1 and in commercial service for many years was tested and also performed well. The design work and testing were funded separately by Consolidated Edison Co. of New York. A third design, fitting approach 2, uses lengthwise rigid rods. The splices were not adequately tied to the rods with nylon tape, and the splice failed because of slippage. A design modification is being considered to rectify the weakness. *Project Manager: John F. Shimshock*

DISTRIBUTION

Novel methods for cable analysis

EPRI has sponsored investigations using advanced analytic techniques for solid dielectric insulation since 1983. The purpose of this work is to evaluate the merits of novel methods—for example, thermogravimetric analysis, gas chromatography, Fourier transform infrared analysis, and mass spectrometry. The projects are structured so that most test development work is being performed on insulation obtained from field-aged cables, and researchers are gathering valuable information.

The University of Connecticut has tested more than 60 samples thus far (RP7897-1), and five major volatile components have been identified in the insulation. Some volatiles remain in the insulation despite years of field aging. These volatiles are cumyl alcohol, acetophenone, acetic acid, α-methyl styrene, and cumene. (Prior work had identified only three products.) Many additional components in small quantities have also been found.

Under a separate contract the Institut de Recherche de l'Hydro-Québec has shown that density varies across the width of solid dielectric insulation, which is believed to be partially caused by the migration of contaminants out of the cable shield (RP7897-2). Neutron activation analysis (NAA) confirms this view because it identified various ions in the insulation wall, most of them concentrated near the shields. All cables examined show residual physical stress under polarized light, and water halos have been identified.

These methods are only a few of the numerous techniques being explored. This work will continue into 1987 to further define the effects measured and evaluate their meaning; a menu of test procedures indicating the information that can be obtained from them will be devised. *Project Manager: Bruce Bernstein*

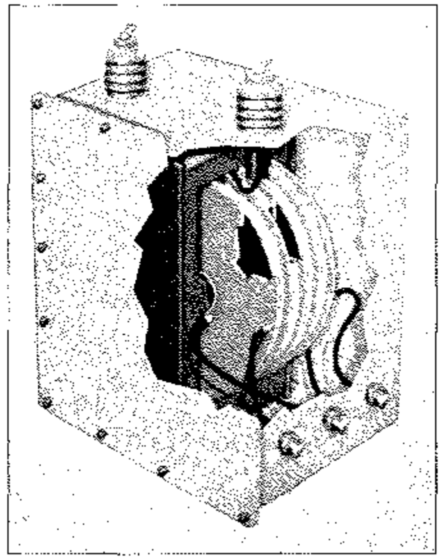
Oilless distribution transformer

Decomposition and ignition of insulating materials can cause oil-filled distribution transformers to fail violently. The objective of research project RP1143, being conducted by McGraw-Edison Co., is to develop a distribution transformer that does not have oil and paper insulation and is not subject to these destructive failures.

Phase 1 of this project was to prove the feasibility of an all inorganically insulated distribution transformer. This study was both an examination of the basic properties of a wide variety of inorganic insulating materials and a study of methods for applying these materials. The results of Phase 1 indicated that it was possible to build totally inorganically insulated transformers that would have essentially the same performance characteristics as conventional oil-filled units.

Phase 2 was then initiated to design, construct, and field test completely oilless, inorganically insulated distribution transformers. Researchers developed a pancake coil design that used aluminum strip conductors. This design has two high-voltage sections and two low-voltage sections, which are coaxial rather than concentric as in a typical distribution transformer. The insulation system contains silicone, fiberglass, and mica materials to withstand the high temperatures encountered without degrading. In Phase 2, 20 prototype 25-kVA single-phase pole-top transformers were constructed for field trials. Project personnel selected this transformer size and type because the transformers could be easily handled and would subject the test equipment to the most rigorous field conditions. These transformers have a 5200-V primary with a 120/240 secondary. Figure 1 shows the overall design of the transformer and the pancake high- and low-voltage windings. Extensive laboratory tests were made on this design, including dielectric and short-circuit strength as well as heat-run and temperature cycling performance. At the successful conclusion of these design tests, researchers constructed and installed 20 field test units on five different utility systems. Figure 2 shows one installation at Texas Power & Light Co., which was energized in August 1984. To date, all the transformers are performing successfully.

Figure 1 Cutaway view of 25-kVA nondestructive distribution transformer.



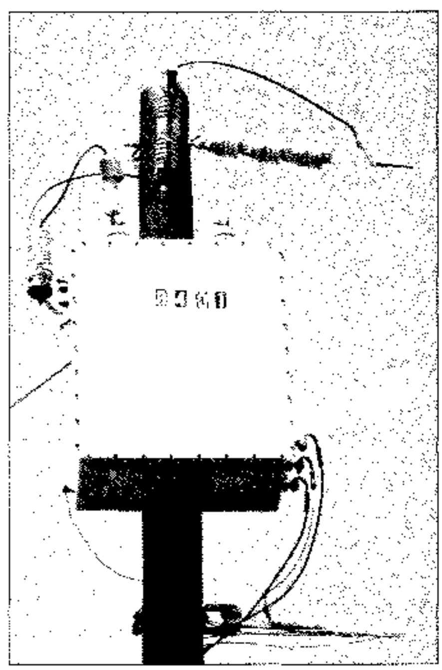


Figure 2 A 25-kVA nondestructive distribution transformer installed for field tests at Texas Power & Light Co.

The goals of Phase 2 were to improve the efficiency of the transformers and reduce their size primarily by developing rectangular winding, to continue materials development, and to add tap changers and explore dual voltage capability. Early in this phase McGraw-Edison did a marketing study that drew the following conclusions.

- Unless and until a very high volume production is reached, this nondestructive transformer technology would not be cost-competitive with conventional pole-mounted, oil-filled distribution transformers. The nondestructive technology would only be used for critical applications because of its higher cost.

- The initial applications of the nondestructive transformer technology will be in sizes larger than 25 kVA. To significantly penetrate the market in utility vault-type and commercial building applications and in industrial applications for replacement of PCB-filled transformers, transformer size should be extended to at least three-phase 500 kVA or single-phase 167 kVA.

Design studies indicated that this technology could be used in these large sizes. Initial designs were developed to produce 100-kVA single-phase units, which were the largest units that could be handled readily at the McGraw-Edison Technical Center. Shortly after it made these studies, McGraw-Edison was absorbed by Cooper Industries. The new management does not expect to commercialize this technology. Further development has stopped, except for several tests currently under way. The completed results, tests, and designs will then be thoroughly documented so that EPRI can find another manufacturer to construct larger pad-mounted field test units and to commercialize this technology.

This technology is viable and has an important place in utility systems. It has the following main features.

- Eliminates flammable dielectric materials
- Extends overload capability
- Is environmentally safe
- Is suitable for critical locations

EPRI intends to pursue the development of this technology by seeking proposals from other manufacturers. *Project Manager: Joseph Porter*

Development of improved protective equipment for linemen

EPRI has begun the third phase of a research project to develop improved protective clothing materials for linemen who work on or near high-voltage electric distribution lines (RP2239). The research contractor is Battelle, Columbus Laboratories.

The results of Battelle's study for EPRI may lead to lighter, more flexible, and stronger sleeves, gloves, and other accessories that protect utility workers from contact with high-voltage conductors.

In the first phase of the program, experts examined and identified linemen's needs and developed potential approaches for improving the equipment.

The researchers have evaluated various materials for tear and puncture resistance and flexibility, as well as dielectric strength. They initially screened many elastomeric or polymeric material families before selecting final candidate materials for the protective equipment.

Of primary consideration during the screening process are the electrical properties, although wearer comfort and ease of use are also major considerations. Other improvements to be sought are durability, weight, touch sensitivity, and fuel and oil resistance. Now that final materials have been selected, researchers will prepare initial detailed designs for improved protective equipment, based on these factors.

In the final phases of the program, Battelle researchers will work with a manufacturer to fabricate prototype equipment for field evaluation by utility line crews. They also will coordinate responses from those crews on the potential acceptance and effectiveness of the equipment. *Project Manager: T. J. Kendrew*

OVERHEAD TRANSMISSION

Conductor fatigue life research

Aeolian vibration is a wind-induced phenomenon that has plagued transmission line designers throughout the world. The vibrations are characterized by their short wavelength, relatively high frequency, and low amplitude. This vibration can cause fatigue damage to individual conductor strands and other transmission line components. These effects are the subject of this project (RP1278).

For severely damaged lines, reconductoring or splicing of damaged conductors and adding vibration damping devices is the accepted practice. For minimally damaged lines (one to four strand breaks), the perennial question has been whether the addition of vibration devices would be sufficient to arrest further damage without the considerable expense of reconductoring or splicing. To address this question, Auburn University constructed a test bed and vibrated lines until they were minimally damaged. The vibration amplitude was then reduced to simulate the addition of dampers, and tests were continued. For the range of conductor sizes tested, this method proved an effective offsetting one and could enable lines to achieve their field design life. The results of this work are reported in EL-1946.

Researchers then expanded the range of vibration amplitudes and number of vibration cycles tested. This work confirmed the conclusions reached earlier and provided guidelines for several representative sizes of aluminum conductors, steel reinforced (ACSR). In addition, load-N curves (dynamic bending stress versus the number of vibration cycles) were developed. EPRI report EL-3297 presents the results of this work.

Auburn University then continued its work to evaluate a wider range of Drake ACSR conductors, evaluate the effect of suspension clamp geometry, examine the validity of Miner's cumulative damage hypothesis, evaluate this effect on ACSR conductors, and develop an aeolian fatigue design model/procedure for overhead conductors. This work has recently been completed, and a draft final report is being reviewed. Results indicate that Miner's cumulative damage hypothesis is somewhat conservative for Drake ACSR conductors but that it can be assumed to be valid for design purposes. This investigation also showed that both the static and dynamic strain levels increased significantly with decreasing clamp radius of curvature and that the fatigue performance decreased with the increased strain levels.

Researchers applied the testing procedure used in earlier work on ACSR conductors to a 649.5-kcmil ACSR 18/19 conductor and established vibration amplitude reduction factors to mitigate fatigue damage for this conductor size.

To develop a fatigue design model/procedure, investigators conducted a statistical analysis on data supplied by Georgia Power Co. (GPC). This work suggested that a statistical/probabilistic approach provides the most rational and effective means of evaluating the performance of a conductor subjected to aeolian fatigue. A probabilistic model was then developed and this methodology applied to other lines on the GPC system.

Work is continuing that will expand the laboratory testing of various conductor types, line sag angles, line tension, and suspension hardware. In addition, field work is being started to monitor line vibration activity and site wind conditions to identify appropriate wind versus vibration activity and transformation functions. This work will also attempt to better quantify the effect of site terrain, seasonal temperatures, line characteristics, and wind conditions on aeolian fatigue load-N curves for overhead transmission lines. Line hardware and line tower interactions will also be studied. *Project Manager: Joseph Porter*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Vice President

HEAT PUMP PERFORMANCE AND RELIABILITY

EPRI's heat pump R&D covers a wide array of products, applications, and related issues. Activities in progress include the development of an entirely new heat pump system (a joint effort with Carrier Corp.), the development of modified thermodynamic cycles, an investigation of new working fluids, and work to improve compressors. Others involve laboratory and field testing of new heat pump equipment or new applications of existing equipment. Such testing helps determine actual performance and identify areas for product improvement or new product development. Still other activities are aimed at establishing and disseminating accurate information on heat pump life and maintenance characteristics. These, too, can help identify avenues of heat pump improvement. This status report focuses on recently published results from heat pump life and reliability studies and from field testing.

Reliability studies

The major thrusts of EPRI's research on heat pump reliability, which began in 1984, are to obtain data on the life of heat pump systems and their major components and on repair costs; to determine the most frequent operating problems; and to develop solutions to problems that are identified. Already the work is serving an important purpose: to document for utilities and consumers that actual heat pump life is much longer and maintenance characteristics are far better than conventionally thought. And eventually it should lead to improvements in component and system designs, controls, diagnostic devices, repair techniques, and training materials.

To date, three studies on heat pump life and maintenance have been completed: two surveys of heat pump owners and an examination of maintenance data collected in connection with a heat pump maintenance contract program. The results cover both southern and northern climates. Alabama Power Co. and Commonwealth Edison Co., Inc., managed the surveys. Both have maintained records of heat pump installations for a number of years, making it possible to locate older units and to independently confirm installation dates. In addition, Alabama Power has operated a maintenance contract program for nearly two decades and has developed extensive records on nearly 20,000 heat pumps.

The survey of 1689 heat pumps in Alabama (EPRI EM-4163) found the overall median service life (the age at which 50% of the units have been removed from service and 50% remain in service) to be slightly more than 20 years, far greater than the commonly cited estimates of 5–12 years. When the data are broken down by heat pump manufacturer, median service life ranges from 16 years to more than 20 years. Because no heat pump in the Alabama survey was older than 20 years, median service life could not be precisely determined for brands with more than 50% still in use after 20 years. Figure 1 shows the percentage of heat pumps still in service as a function of their age.

A survey of 684 heat pumps in Commonwealth Edison's service area (northern Illinois, including Chicago) found the median service life to be between 15 and 16 years (EM-4660). The service life curve for this survey is also shown in Figure 1.

The differences in service life between the two studies are not necessarily due to climate: there was evidence that the quality of installation and repair work on heat pumps in the Chicago area was initially somewhat lower than in Alabama. That problem appears to have self-corrected as a result of free-market forces, and units installed or maintained since 1980 have had far fewer repairs than in earlier years. Another factor that could account for the difference in service life in the two studies was the tendency of owners in the Chicago area to upgrade to higher-efficiency heat pumps sooner than owners in Alabama.

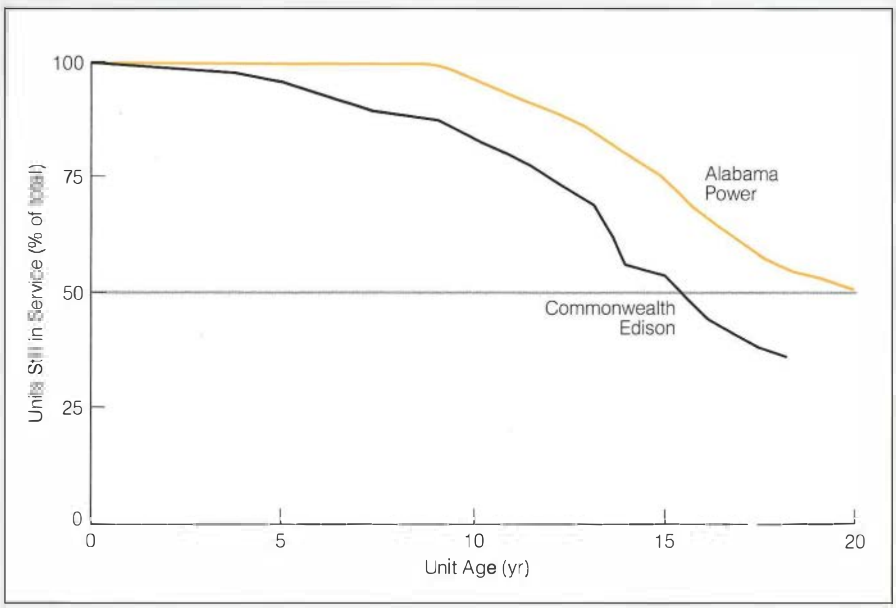


Figure 1 A survey by Alabama Power Co. covering 1689 heat pumps found the median service life (i.e., the age at which half the original units are still in use) to be slightly over 20 years. A survey by Commonwealth Edison Co. covering 684 units in Illinois found the median service life to be between 15 and 16 years.

Many of the other results from the two surveys were strikingly similar. For example, the predominant reason for deciding to replace units appears to have been the age of a heat pump in relation to the owner's expectation of how long the unit would last, coupled with such marketing influences as a repair person's recommendation, promotions and rebates, and tax incentives. Although operational problems influenced the exact timing of replacement in some cases, both surveys revealed that nearly half of the units replaced were still fully operational. This finding dispels the misconception that equipment malfunction determines service life. If a major component failure occurred early in a unit's life, as the owner perceived it, the heat pump was normally repaired rather than replaced. Both studies found that 96% of the original heat pump owners still had heat pumps.

The Chicago-area survey also collected heat pump maintenance information; one category analyzed was compressor life. Similar information was obtained from the Alabama Power maintenance record data base, which details maintenance performed as far as 10 years into a heat pump's life (EM-4659). Both studies found that the median service life for original factory-installed compressors was significantly greater than 10 years. In Alabama 59% of original compressors were still in use, and in Chicago, where the average vintage of heat pumps was newer, 69% were still in use at 10 years. Both studies indicate that the failure rate of compressors in heat pumps installed since 1980 is much lower than that of earlier-vintage units. If these trends continue, compressor service life in newer units could be much longer than the averages cited here.

Multiple compressor replacements were rare. The median service life of second compressors in the Alabama study was at least 8.9 years—and probably longer, because this calculation overrepresents brands with the shortest lives. In the Chicago study, only about 3% of heat pumps installed in any given year since 1965 had had multiple compressor replacements except for the 1975–1979 period, where the value was 7%. In both areas the results indicate that over the typical 15–20-year median service life of heat pump systems, the average owner can expect to replace the compressor no more than once. Indeed, the Chicago study found that a steadily increasing percentage of heat pumps were surpassing the 15–16-year median service life without ever having a compressor failure; for units installed as late as 1970, the figure is 40%.

EPRI's heat pump reliability work is continuing. A report describing heat pump maintenance costs in Alabama is nearing completion. Research to identify cause-and-effect relationships between failure modes is planned for the near future. Much has already been learned about the most frequent problems with heat pumps, and plans are being made to identify specific component development programs, repair techniques, and educational materials that will best resolve those problems.

Research in this area has demonstrated that heat pumps are already far more reliable than commonly believed; the fact is that much more publicity has historically been given to the relatively few troublesome heat pumps than to the many well-functioning units. Further improvements in heat pump reliability are still possible, however, and EPRI intends to pursue appropriate research on those improvements.

Field testing

Many electric utilities encourage heat pump use because, unlike air conditioners, heat pumps operate year-round. The more uniform electrical demand that results means a more effective utilization of generating capacity, which in turn allows lower per-unit electricity prices. Some utilities are reluctant to promote heat pumps, however, because of uncertainty about how the equipment performs in their climate. Field tests conducted by EPRI and others can help a utility decide what types of heat pumps will be beneficial to both the utility and its customers and what levels of performance should be promoted.

EPRI has sponsored many field evaluations by many contractors since the mid 1970s; 12 reports on this testing have been published to date. The purpose of the monitoring is not only to determine seasonal performance and efficiency information but also to identify potential problems and test improvements in design. The results have been used by EPRI in directing its heat pump development activities and by electric utilities in structuring their marketing programs.

In the early field tests, heat pumps were alternated on a periodic basis with electric resistance heating, and the energy consumption of both types of equipment was monitored. Seasonal efficiency was determined by dividing the energy consumption of the resistance heater by that of the heat pump. This approach is inadequate for newer heat pumps, however, which have many more features and operating modes. In order to evaluate the subtle differences between equipment types and operating strategies, more-recent tests have collected detailed engineering information on cycling rates, defrost losses, and other aspects of heat pump system performance.

EPRI has field-tested a range of heat pump types, including single package, dual split, triple split, dual compressor, two speed, triple split with desuperheater water heating, triple split with full condensing water heating, room units, package terminal units, variable speed (inverter drive), dedicated heat pump water heaters, groundwater source, hydronic, add-on units for gas or oil furnaces, dual fuel, ground coupled, crawl space earth coupled, and solar assisted. Testing has been conducted in 16 states around the country: Alabama, Arkansas, California, Florida, Georgia, Illinois, Massachusetts, Minnesota, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Tennessee, Texas, and Washington.

Results from the most recent project reports, which cover testing in 1980–1983, are highlighted below (EM-4674, EM-3978). Tests begun since then are in various stages of completion, but final results are not yet published.

Two measures of a heat pump's performance are its heating seasonal performance factor (HSPF) and its cooling seasonal energy efficiency ratio (SEER); these are ratios of the total heat energy delivered (heating mode) or removed (cooling mode) during a season to the total electric energy consumed. For heat pumps with electric resistance backup, HSPFs were typically in the range of 5.2 to 7.0 Btu/Wh, depending on climate and equipment type, size, and usage patterns. For heat pumps with fossil fuel backup, HSPFs were typically around 7.7 Btu/Wh. Cooling SEERs for the heat pumps in the 1980–1983 tests typically ranged from 6.0 to 9.0 Btu/Wh, again depending on climate and equipment type, size, and usage patterns. No tests have yet been completed on the high-efficiency heat pumps that have become available in the last few years.

Many of the recently tested heat pumps demonstrated significant reductions in one-hour peak electrical demand when compared with electric resistance heating and older heat pump models. The peak demand of the newer heat pumps was 1.0–2.0 kW below that of older models and 1.0–4.0 kW below that of electric resistance heating. With add-on and dual-fuel heat pumps in cold climates, the peak electrical demand reductions ranged from 10.0 to 18.0 kW because in these cases the heat pumps did not operate at low ambient temperatures.

EPRI has conducted research to refine and validate computer modeling techniques for simulating the performance of many heat pump types in any climate. These computer models, combined with field performance data, greatly enhance our understanding of the performance and economics of heat pumps operating in the field. Moreover, EPRI frequently works with interested utilities to perform field tests on equipment having new features. The results thus receive wide dissemination at a lower cost to both EPRI and the utility. *Project Manager: Carl Hiller*

R&D Status Report
ENVIRONMENT DIVISION

Stephen Peck, Acting Director

CAPACITY PLANNING UNDER UNCERTAINTY: THE VALUE OF DECISION FLEXIBILITY

Given the uncertainties in the current utility planning environment, technologies that offer greater flexibility to delay, cancel, or speed construction are potentially valuable. Traditionally, utilities have not quantified the benefits of this flexibility. EPRI research is giving utility planners tools to evaluate the decision flexibility associated with different technologies.

Utility planners today face uncertainty in demand growth, costs, environmental requirements, and the potential to buy and sell power outside of individual service territories. The ability to adjust capacity plans as the future unfolds depends on such technological attributes as size, lead time, potential for phased construction, and ability to burn various types of fuel. For example, small power generation additions allow closer matching of demand and capacity and thus reduce the likelihood of periods of capacity shortage or excess. Shorter construction periods reduce exposure to risks due to uncertainties in construction costs, electricity demand, and environmental requirements. Technologies that allow decision flexibility can reduce both generation cost and investor risk.

EPRI is sponsoring research to develop insights about the benefits of decision flexibility and to produce new capacity planning methods. These new methods are being designed to quantify all the economic benefits of alternative capacity planning strategies, including the benefits of decision flexibility.

Basic principles

In the 1960s and early 1970s, load was growing rapidly and smoothly, and there was widespread belief in significant economies of scale. This environment led to capacity expansion strategies based on the use of large-scale technologies. In the 1980s conditions have changed: load growth is lower, future load is recognized as uncertain, and scale economies are being questioned. These changes imply a greater role for smaller-scale technologies and technologies that allow decision flexibility. The question is how to quantify the trade-offs among technologies with different degrees of decision flexibility.

The value of a capital project can be separated conceptually into three components: (1) the value of the project assuming that construction is completed, minus (2) the cost of construction assuming that construction is completed, plus (3) the value of the ability to delay, advance, or abandon the project before construction is completed. Traditionally, capacity planning has focused on the first two components. The third component, the value of decision flexibility, is usually not quantified. In an uncertain world, however, arriving at least-cost investment strategies requires careful consideration of the value of flexibility.

There are two reasons why conventional capacity planning analyses do not consider decision flexibility. First, many planning models evolved when the importance of uncertainty was not widely recognized. Second, even when uncertainties are recognized, estimating the present value of the options (future decisions) that allow one to hedge against bad outcomes is a difficult task at best. Specifically, using risk-adjusted discount rates to calculate the present value of future decisions is not appropriate.

Conventional utility system planning recognizes the trade-off between economies of scale and temporary overcapacity when large but cost-effective machines are put in the rate base. With exponential load growth and the existence of scale economies, a firm will install ever larger turbogenerator sets at constant intervals of time (called cycle time) to minimize costs. Without economies of scale, very small plants should be built one after the other. With lower load growth, the least-cost unit size is reduced proportionally.

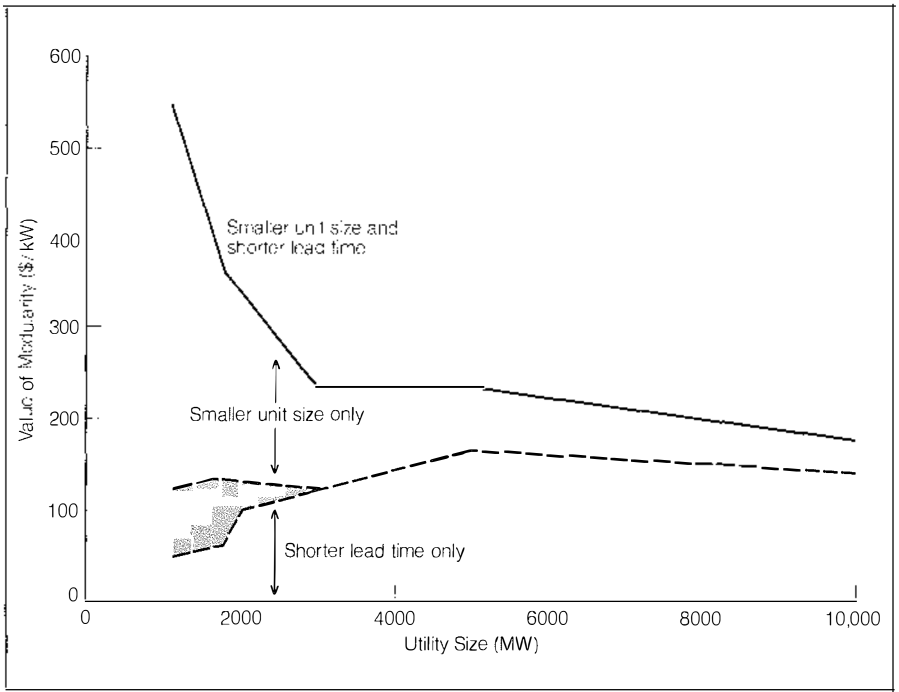
In the 1960s and early 1970s, utilities tended to build to a two-year cycle time. Today's reduced demand growth and lower expectations about economies of scale suggest that utilities will use smaller technologies in the late 1980s and perhaps beyond; Table 1 illustrates the point. (For a discussion of the constant-cycle-

Table 1
EFFECT OF LOWER DEMAND GROWTH AND SHORTER CYCLE TIME ON OPTIMAL PLANT SIZE

Year	Utility System Size (MW)	Annual Growth Rate (%)	Annual Demand Increment (MW)	Cycle Time (yr)	Optimal Plant Size (MW)
1970	5000	7	350	2	700
1980	6700	3	200	2	400
1985	8000	3	240	2	480
				1	240
1990	9000	3	270	2	540
				1	270

time concept and related models and the implications for today's planning environment, see "Evolving Technologies, Utility Incentives, and Alternative Financing and Cost Recovery Methods," *Resources and Energy,* Vol. 7, No. 1 [March 1985], by Stephen Peck, Stephen Chapel, and Stanley Vejtasa.)

Figure 1 The value of modular technologies to ratepayers was analyzed as a function of utility size. The solid curve represents the benefit when a utility adds a small plant (125 MW) with a short lead time (two years) to its system instead of a larger plant that takes longer to build (500 MW, four-year lead time). It shows that the value of modularity increases as utility size decreases. The analysis also considered the effects of small unit size and short lead time separately. It was found that as utility size decreases, the unit size benefit grows in proportion to the lead time benefit. The two factors appear to have a synergistic effect for small utilities (shaded area); that is, the total benefit is greater than the sum of the unit size benefit and the lead time benefit.



Completed research

Three research projects on the value of decision flexibility have been completed. The first two used EPRI's over/under capacity planning model to evaluate capacity planning strategies involving smaller technologies with shorter lead times. This model, which is described in EPRI EA-3149-CCM, captures the trade-offs identified by the cycle-time models mentioned above. It also recognizes demand uncertainty and can speed up or slow down the start of projects in response to projected demand outcomes, although it does not allow for the abandonment of a project during construction. The third research project used financial option methods to estimate the value of opportunities to abandon or delay construction.

The initial research on decision flexibility (EA/CS-4158) assessed the impact of modularity on utility investment decisions by examining turbocharged-boiler technologies. Using the over/under model, project analysts reached the following conclusions about the benefits to utility customers of capacity additions involving shorter-lead-time, smaller (modular) technologies.

- The value of modularity is significant ($100 to $300/kW) over a wide range of assumptions and utility system configurations.

- The value of modularity is greater for small utilities than for large ones (Figure 1). Breaking the value down into its components shows that for small utilities, the benefits of smaller unit size are greater than the benefits of shorter lead time (assuming that none of the capacity can be sold off-system when not needed); for large utilities, however, the benefits of shorter lead time are much greater than the benefits of smaller unit size.

- For large utilities, the value of modularity is relatively insensitive to the rate of demand growth; for small utilities, the value of modularity increases as demand growth declines.

- Demand uncertainty increases the value of modular coal plants, but the availability of combustion turbines tends to reduce this effect.

The second project on decision flexibility (RP1432) used an improved financial model that allows analysts to quantify how utility shareholders are affected by alternative generation investment strategies. The new model was implemented as a module in the over/under model (it is described in the documentation for Version 3.0 of that model). Then, the improved over/under model was used to estimate the shareholder benefits of modularity. The results, which are presented in a draft report available from the EPRI project manager, are summarized below.

- Modularity has value to shareholders under commonly assumed conditions in the utility industry.

- Given regulatory rules that penalize all capital investment equally, a modular technology does not yield large savings for investors except when the smaller modular units allow a utility to reduce its reserve margin and thus the amount invested. More focused regulatory rules, such as excess capacity rules, do yield a significant value for modularity.

- The relative risks of modular and conventional technologies are important. If a modular technology has higher technological risk (i.e., if the plant may not be built on schedule or may have poor operating characteristics), then the value of modularity is much lower.

The third completed project (RP2379) used financial option valuation methods to quantify the value of the planning flexibility associated with shorter-lead-time technologies—specifically, the value of the option to abandon construction. The analysis confirmed that the value of this option, which is part of any investment, may be a significant fraction of a plant's construction cost. This is especially likely when regulatory and demand uncertainty combine to make the value of a completed plant difficult to forecast.

The analysis found that the opportunity to delay or abandon construction has greater value with shorter-lead-time plants for two reasons: more information is available before funds are spent, and more money is saved if construction is canceled (because the construction expenses are concentrated closer to the completion date). The results indicate that explicitly considering the value of the option to abandon (or delay) construction can be important for a complete analysis of shorter-lead-time plants. A draft report on this study is available from the EPRI project manager.

Ongoing research

A clear set of lessons has emerged from the over/under analyses and the value-of-abandonment research. First, there can be significant benefits associated with technologies of shorter lead time and smaller size. A large part of the benefit is due to greater decision flexibility. Second, quantifying flexibility benefits is difficult and requires a new type of capacity planning analysis. The value-of-modularity research described above exemplifies the necessary approach. Third, explicit consideration of decision flexibility will change the traditional view of a least-cost capacity strategy in that smaller, shorter-lead-time technologies will assume more importance and it will become accepted that under some conditions the prudent option is to cancel or delay capacity additions and recover sunk costs.

Current efforts are building on the earlier research to develop a conceptual design for a fundamentally new type of capacity planning process, one that will take account of the value of decision flexibility. In this research dynamic programming and financial option methods are being applied to the problem of choosing least-cost strategies when demand is uncertain. The methodology is based on the investment principle that at any given time, a capacity addition project should be completed if the value to customers of completing the project exceeds the incremental construction costs entailed; otherwise the project should be canceled, and prudently spent sunk costs should be recovered from utility customers. This fundamental strategy assumes that the total cost of a project includes the cost of the capital provided by utility shareholders. The strategy involves continually updating information and reviewing the investment decision.

If this strategy is not understood and followed by utility decision makers and regulators, it is likely that costs will not be minimized. Two examples illustrate the extreme cases. First, suppose a project should be canceled (its value is less than the incremental construction costs), but regulators follow a policy of not allowing recovery of the sunk costs. The utility will want to complete the project and get full cost recovery—that is, it will not follow the least-cost strategy. Second, suppose a project should be completed (the incremental construction costs are less than the value of the plant at completion), but regulators indicate that they will not allow the plant in the rate base at completion. The utility will want to cancel the plant and cut its losses, again not following the least-cost strategy.

The methodology being developed will help utilities identify capacity planning strategies that are least-cost in a broader context than traditional planning has allowed. The research is also intended to help regulators evaluate prudence in this broader context—a context that assumes the need for decision flexibility. *Project Manager: Stephen W. Chapel*

URBAN POWER PLANT PLUME STUDY

Recently EPA began requiring that all air pollution sources in urban areas be modeled for regulatory compliance by using dispersion coefficients derived from a special study conducted in St. Louis. Models with these coefficients predict significantly higher concentrations for sources with tall stacks (e.g., power plants) than models used earlier and thus lead to stricter emission limits. As an adjunct to EPRI's plume model validation and development project (RP1616), in 1985 a special study was conducted at an urban site to collect data for use in evaluating the EPA models applied to urban generating stations (RP2736-1). Indianapolis Power & Light Co. (IP&L) and the Empire State Electric Energy Research Corp. cofunded this urban site study with EPRI.

In 1978 EPRI undertook a significant experimental and analytic project, the plume model validation and development project, designed to evaluate the atmospheric dispersion models being applied to electric generating stations and to provide data bases for developing improved models. The project has amassed a significant data base on plume behavior covering a range of meteorological conditions and terrains.

The urban site study under RP2736-1 entailed an intensive field measurement program in Indianapolis, Indiana, around the Perry-K station, which is owned and operated by IP&L. Perry-K is situated approximately 1 km southwest of Monument Circle, the urban center of Indianapolis. In addition to producing electricity for the utility grid, the plant produces steam for several customers in the downtown area for heating, air conditioning, and manufacturing purposes. The load is quite stable, and Units 11 and 12, used for this study, produce steam at a fairly constant rate of 250,000 lb/h (31.5 kg/s).

The program at Perry-K included four weeks of measurement of plume dispersion and coincident measurement of meteorological and plant emission variables. The resulting data have been used to evaluate air quality models applied to sources in urban areas. Specifically, the ISC (industrial source complex) model, run in two of its urban modes, and RAM (rural atmospheric model) were tested. Model predictions were systematically compared with observed concentrations of stack emissions at various distances from the source. The analysis was designed to assess the performance of the models as they would be applied in a regulatory setting.

Measurement program

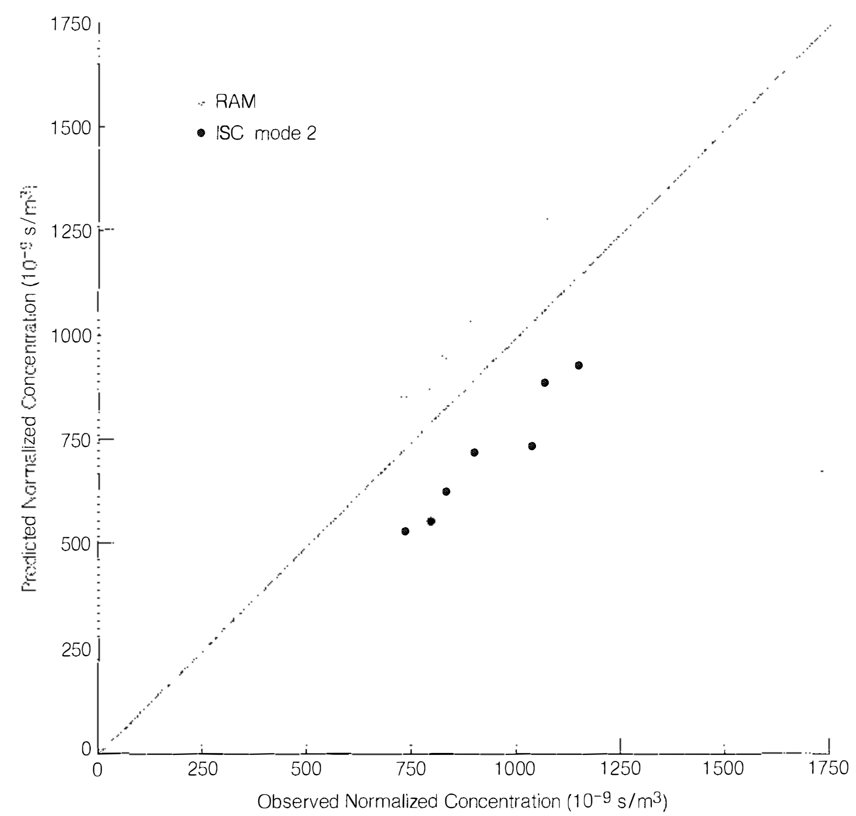
Urban areas have less exposed soil and vegetative cover than do rural areas. As a result, during daylight hours urban areas have higher temperatures than rural areas (hence the term *urban heat island*), as well as lower relative humidity and stronger atmospheric mixing. In addition, buildings act both to decrease near-surface wind speeds and to induce mechanical mixing. The greater turbulence and mixing depths resulting from these thermal and mechanical phenomena have been assumed to cause power plant plumes to disperse more rapidly in urban areas. The path of a plume from an urban plant may also be affected by aerodynamic steering around large buildings and by local flow patterns generated by the urban heat island.

The design of the urban site experiment was based on the designs used for the earlier field measurement sites in EPRI's plume model project—a plains site and a site featuring moderately complex terrain. This approach made it possible to compare the results of the programs directly and to test the transferability of models from site to site.

The pattern of ground-level plume gas concentrations was mapped in an atmospheric tracer program. Sulfur hexafluoride (SF_6), a safe, inert gas detectable at the parts-per-trillion level, was injected into stack number 3 at Perry-K and was sampled by approximately 175 automated syringe samplers arrayed in eight or nine arcs downwind of the plant. The sampler locations for each test day were selected on the basis of forecast meteorological conditions. Different arc distances and directions were instrumented, depending on the forecast dispersion conditions. Each sampler collected nine consecutive 1-hour samples, each of which was assayed to determine the time history of tracer gas concentrations. During the four-week experimental period, 170 hours of sampling yielded over 25,000 concentration observations. The tracer gas emission rate was carefully monitored, as were the stack variables required as model input, including stack gas temperature and velocity.

Measurements of plume rise and plume distribution aloft were provided by laser radars (lidars). A system called Dial (differential absorption lidar) measured the sulfur dioxide distribution in the plume; it was deployed to mon-

Figure 2 Measurements of plume dispersion from the urban site study were used to evaluate RAM and ISC—two air quality models applied to urban power plants. Shown here are results from a comparison of the highest observed and predicted 1-hour-average normalized concentrations (unpaired in time or location). The normalized concentrations were determined by dividing the observed and predicted concentrations by the stack gas emission rate; they are reported in units of 10^{-9} s/m^3.



itor the plume's location and cross section at approximately 0.5–1.0 km downwind of the stack. A system called Alpha-1 (airborne lidar for plume and haze analysis), which measures particle distribution, was used to monitor the plume's location and cross section at distances out to approximately 5 km from the stack. Both lidar units were developed by SRI International under EPRI sponsorship.

The project operated three 11-m meteorological towers, which were located in the downtown area, in a suburban neighborhood, and at a rural site southwest of the city. The towers were instrumented for monitoring wind speed, wind direction, air temperature, vertical temperature differences, dew point, three-dimensional turbulence, and heat flux. The urban and rural sites also recorded solar, sky, and net radiation intensity. These surface-level measurements were supplemented by National Weather Service data collected at the Indianapolis Airport and by meteorological data collected in the urban area by IP&L and various local air quality agencies. To quantify the size of the urban heat island, 10 hygrothermographs were deployed throughout the monitoring domain, and infrared satellite images were obtained from the National Satellite Data Service. Estimates of the major anthropogenic heat sources in the Indianapolis area, such as power production and transportation, were also made.

Rawinsondes were used to measure mixed-layer wind, temperature, and humidity. There were two sonde-launching sites: a rural site adjacent to the rural meteorological observation tower and an urban site approximately 0.5 km west of the stack.

Model evaluation

Two EPA models were evaluated—RAM and the ISC model, which was run in two urban modes. RAM, the model favored by EPA, employs dispersion coefficients based on an earlier urban study conducted in St. Louis. The ISC model has often been adapted to urban settings by adjusting the dispersion coefficients. The model has an option for modifying dispersion to account for downwash caused by large obstacles near the stack. The two ISC modes differ in the way the dispersion coefficients are modified for stable atmospheric conditions.

The models were evaluated by comparing their predictions of ground-level concentrations around the Perry-K station with tracer concentrations measured during the experimental period. Prediction accuracy was examined as a function of distance from the source and of atmospheric stability.

As with the plains site and the moderately complex terrain site, there was great variation between the predicted and measured concentrations. The urban models tested were unable to successfully predict concentrations at a particular time or location. The overall bias of the results was examined by comparing the distributions of predicted and observed concentrations; the following conclusions emerged.

- ISC mode 1 significantly underpredicted the tracer concentrations for all time periods. Its predicted maximum concentrations were approximately 50% of the observed values.

- ISC mode 2 predicted maximum concentrations that were approximately 80% of those observed. The downwash option was not used for these predictions.

- The RAM predictions were approximately 20% higher than the observed maximum hourly concentrations. Thus RAM overpredicted concentrations by about the same amount that ISC mode 2 underpredicted them (Figure 2).

In summary, the models tested failed to demonstrate superior performance. Continued model development through EPRI's plume model project is expected to lead to improved models in the next two years. In the meantime, the best estimate of maximum urban power plant plume concentrations lies between the RAM predictions and the ISC mode 2 predictions. *Program Manager: Glenn R. Hilst*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Vice President

SOURCE–TERM EXPERIMENTS: RECENT RESULTS

The source term is the amount, type, and timing of predicted radioactivity release in a severe nuclear reactor accident. Accidents that involve severe fuel damage are referred to as severe accidents. The content and accuracy of analytic models that are used to predict source terms for severe accidents must be evaluated against appropriate experimental data. An EPRI test program is being carried out to provide such data and thus improve the accuracy of the source-term models.

The Source-Term Experiments Program (STEP) is sponsored by a consortium organized and headed by EPRI (RP2351). The other members include Ontario Hydro (Canada), DOE, NRC, and Belgonucléaire (Belgium). The program focuses on the physical and chemical characterization of the radioactive fission products that might be released if the fuel rods were extensively damaged by overheating during an accident in a light water reactor. The investigation is carried out by subjecting irradiated test fuel (i.e., fuel containing fission products) to temperature and steam flow transients similar to those that would be encountered in severe reactor accidents. This is done in a specially instrumented test vehicle that allows the test fuel to be heated by the fissioning of the fuel material itself, using neutrons from a driver reactor (TREAT). Samples of the flowing mixture of steam, hydrogen, and fission products are collected for posttest examination and analysis. The program also yields some supporting data about the timing and extent of hydrogen generation, the timing of fuel degradation, and the behavior of control rods during severe accidents.

The system used in the STEP tests contained a test bundle of four fuel rods with 1-m-long (3.3-ft) active fuel sections from the BR-3 prototype power plant operated by Belgonucléaire. These rods are typical of pressurized water reactor fuel, except for length and ^{235}U enrichment, and were irradiated to 3–4 at% burnup. The test fuel bundle was housed in a ceramic (zirconium dioxide) flow tube and insulator cylinder mounted in a high-temperature-alloy (Inconel-625) pressure capsule. Steam was supplied from an external source; hydrogen in the effluent stream was recombined and steam was condensed and stored in an external receiver vessel. System hydraulics were controlled by a programmable metering pump that supplied feedback to a boiler and by a pneumatically activated valve that received position signals from a unit that directly monitored vehicle pressure. The vehicle was thus part of a single-pass, closed system and was trace-heated to maintain temperatures well above saturation temperature to prevent condensation inside the system. Thermocouples were positioned throughout the system to provide a means of recording temperatures for each test.

About 7% of the effluent flow was diverted into each of two aerosol characterization trains. The trains consisted of three sample chambers that could be opened and closed independently during the test. Particulate material was collected in these chambers (1) by gravitational settling on and diffusion to sample coupons oriented horizontally and parallel to the flow, and (2) by impaction on, interception by, and diffusion to fine wires oriented with their axes perpendicular to the flow.

The two sampling ports were located at points about 100 cm (3.3 ft) and 270 cm (8.8 ft) above the midplane of the active fuel column. Additional coupons of various materials were mounted in the aerosol chambers and on a sample tree installed in the space above the fuel to collect vapor, liquid, or solid species entrained in the flowing steam and hydrogen. The deposition coupons on the sample tree were located at three elevations: approximately 100 cm (3.3 ft), 180 cm (5.9 ft), and 260 cm (8.5 ft) above the midplane of the active fuel column. Two hydrogen monitors were incorporated into each experiment: one in the vehicle itself and one in the effluent receiver system.

Four in-pile tests were planned and all four have now been successfully completed. The primary parameters that were varied among the four tests were pressure, fuel heat-up rate, and the presence or absence of control rod material. The STEP-1 and STEP-2 tests were conducted at low pressure at an initial heat-up rate of more than 1 K/s (1.8°F/s) and without control rod material. The STEP-3 and STEP-4 tests were conducted at high pressure and at an initial heat-up rate of less than 1 K/s. The STEP-3 test had no control rod material present, but the STEP-4 test incorporated a central control rod composed of an alloy of silver, indium, and cadmium. The heating periods in the four tests ranged from 20 to 25 min. On-line radiation detectors confirmed that fission product release from the fuel region occurred in all tests, and postirradiation neutron radiography of the in-pile vehicles showed that cladding fracture and axial movement of the fuel had also taken place in each test.

A summary of the principal thermal-hydraulic conditions that were recorded for each experiment is given in Table 1. The performances of the STEP-1 and STEP-2 tests were generally similar in terms of recorded flow channel temperatures in the fuel region, as well as in terms of temperatures measured at downstream locations along the sample tree. Specifically, the flow channel temperatures were observed to peak near the midplane of the test fuel column, and the indicated heat-up rates were roughly equivalent. The downstream temperatures also rose somewhat during the test period in both experiments.

The thermal performances of the STEP-3 and STEP-4 tests, although similar to each other, were quite different from those of the STEP-1 and STEP-2 tests. Note that the recorded flow channel temperatures peaked at a later time and near the top of the fuel column in the STEP-3 and STEP-4 tests. The downstream temperatures in these tests also increased more significantly during the test periods. The thermal behavior in STEP-3 and STEP-4 indicates that a relatively strong natural convection flow loop was established in these tests as a hot, buoyant plume of steam and hydrogen gas rose along the axis of the fuel region and continued to penetrate vertically to higher levels in the capsule. The relatively cooler (more dense) steam near the walls of the in-pile capsule above the fuel region then flowed downward (countercurrent) to complete the internal circulation loop.

This natural convective flow was apparently established in STEP-3 and STEP-4 but not in STEP-1 or STEP-2 because of the higher pressures used in STEP-3 and STEP-4. Because the mass flow rates of input steam were roughly equivalent in all four tests, the corresponding bulk flow velocities through the in-pile vehicle were considerably higher in STEP-1 and STEP-2 (less dense fluid). Analysis has indicated that these bulk flow velocities were strong enough to prevent establishment of buoyancy-driven natural convection in the STEP-1 and STEP-2 tests but not in the STEP-3 and STEP-4 tests. Thermal-hydraulic modeling work is being continued to develop more-detailed interpretations of the overall conditions that prevailed in all the tests.

Nondestructive and destructive examinations that were started after the tests are in various stages of completion for samples and hardware taken from all four tests. Instrumental examinations of a series of stainless steel deposition coupons recovered from the sample trees of each of the test assemblies have been completed. Three coupons (one from each level on the sample tree) from each test were examined. A radiation-shielded scanning electron microscope (SEM) was used to determine morphological characteristics of the deposits; energy-dispersive X-ray (EDX) analysis was used to determine elemental compositions at specific locations in the deposits. Resolution down to about 0.1 μm was obtained.

The SEM results showed that the deposit loadings on the STEP-1 coupons were substantially heavier than those found on the coupons from the other three tests. The deposit loadings from STEP-2 and STEP-3 were approximately the same. Those from STEP-4 were somewhat less heavy. Loadings did not vary substantially with level along the sample tree in any of the tests. It was also observed that the deposits from STEP-1 were the most heterogeneous with respect to form, whereas those from STEP-3 were the most homogeneous. The material on the STEP-3 coupons appears to be more crystalline, and materials from the other tests appear to be more amorphous.

The predominant observed constituents of the deposits from the STEP-1 and STEP-2 tests are tin (from cladding) and the fission products cesium, molybdenum, and rubidium. These elements were most frequently seen in particles (<1 μm) and in irregular masses (≥1 μm). Regularly shaped material (suggesting crystalline structure) with high cesium and molybdenum concentrations was observed. Iodine was seen in conjunction with cesium in a number of crystalline-like deposits on the coupons from the second test. Iodine with cesium was found only once on the coupons from the first test. The iodine-cesium deposits often contained silver, which probably came from silver coupons on the sample tree. Energy spectrum peak-height ratios for these deposits are consistent with that for cesium iodide (CsI).

Rod-shaped pieces with fluted surfaces rich in zirconium were observed on the coupons from both tests. Their fluted structure is consistent with the mechanical disruption of cladding in an oxidizing environment. Smooth spherical particles containing zirconium were also observed. Fragments of fuel were identified on the coupons from each test. Tellurium was detected on the coupons from the first test, but the identification was questionable. Silicon, possibly from test vehicle components or fuel cladding, was observed on the coupons from the second test.

As indicated earlier, the deposits from the STEP-3 test were more homogeneous than those from the first two tests. Iron, from test vehicle components or fuel cladding, is the predominant observed constituent. The deposits also contain rubidium, cesium, silicon, tin, and molybdenum. They are most often in the form of spherical clusters (<1 μm) and

Table 1
STEP THERMAL HYDRAULIC OPERATING CONDITIONS

STEP Test	Nominal Pressure MPa (psia)	Initial Heat-up Rate K/s (°F/min)	Initial-Final Steam Flow g/s (lb/h)	Flow Channel Peak Temperature: Value K (°F)	Flow Channel Peak Temperature: Location* cm (ft)	Time s (min)	Downstream Temperatures Early-Late Versus Location* K (°F): 100 cm (3.3 ft)	180 cm (5.9 ft)	260 cm (8.5 ft)
1	0.32 (46)	1.2 (130)	0.70–0.25 (5.6–2.0)	>1980† (>3100)	~0 (~0)	>600† (>10)	633–672 (680–750)	646–658 (705–725)	578–611 (580–640)
2	0.16‡ (23)	2.4 (259)	0.34–0.22 (2.7–1.7)	>1980† (>3100)	~0 (~0)	>660† (>11)	589–658 (600–725)	656–661 (720–730)	575–594 (575–610)
3	8.00 (1160)	0.6 (65)	0.54–0.23 (4.3–1.8)	2030 (3195)	~40 (~1.3)	1284 (21)	639–922 (690–1200)	650–783 (710–950)	639–700 (690–800)
4	7.86 (1140)	0.5 (54)	0.55–0.27 (4.4–2.1)	1700 (2600)	~50 (~1.6)	1428 (24)	644–1006 (700–1350)	650–867 (710–1100)	644–756 (700–900)

*Location is with respect to the axial midplane of the test fuel column.
†Times and temperatures given correspond to thermocouple failure, at which point data acquisition capability was lost.
‡A pressure rise began at 480 s (8 min) into the test and ultimately reached 1.24 MPa (180 psia), whereupon the steam supply was terminated.

elongated structures of crystalline-like material. Fluted zirconium rods and one zirconium sphere similar to those seen on the coupons from the first two tests were found.

The deposits from the STEP-4 test are primarily particles (<1 μm). Some are composed of iron and silicon, and others are composed of cadmium, molybdenum, and silicon. The cadmium came from the control rod alloy that was present in this test. Irregular particles ($\geq$1 μm) composed of silicon, tin, iron, and chromium were observed. The iron and chromium were from test vehicle components or fuel cladding. Again, fluted zirconium rods and one zirconium sphere were seen. Rubidium was questionably observed. Iodine, tellurium, and uranium were not detected on the coupons from the latter two tests.

The variety of materials and the range of morphologies that characterize the deposits from these tests indicate that a relatively complex mixture of species and forms was carried out of the fuel regions by the flow of steam and hydrogen. A better estimate of the relative amounts of the various components should be possible when the results of wet chemistry analyses of dissolved deposits become available. The principal purpose of the other major posttest analytic effort was to make detailed counts and measurements of sample particles recovered from the wire impactors and settling plates in the various chambers of the aerosol characterization canisters.

Only samples from STEP-1 and STEP-3 have been examined thus far; particle collection efficiency refinements are still being made. However, the data from the STEP-1 samples show two distinct particle populations: those <1 μm and those $\geq$1 μm. The smaller particles outnumber the larger ones by several orders of magnitude and appear to have been formed by nucleation from the vapor phase. The larger particles appear to be agglomerates or small pieces of debris that came from the fuel rods damaged in the STEP-1 tests. Data from the STEP-3 samples are still being processed.

During the coming year the posttest sample analyses and the data processing and reporting efforts on the STEP test series should be completed. The information will be used to evaluate the completeness of analytic models of the release and transport of fission products in severe reactor accidents and to help confirm and improve thermal-hydraulic modeling of such accidents. The STEP aerosol characterization data are expected to provide a particularly useful test of the several aerosol-behavior computer codes that are used to predict the formation and transport of aerosols in assessing severe accidents. *Project Manager: Robert Ritzman*

COMPUTER-AIDED ENGINEERING GUIDELINES

Computer-aided engineering (CAE) technology applied to generating plant design, construction, operations, and maintenance has the potential for substantial improvements in overall plant economics. Significant efforts by computer software/system vendors, architect-engineers, and some utilities are currently under way to develop CAE systems and applications for power plants, particularly in design, operations, and maintenance. However, without a common plant data model that standardizes information, relationships between the data, and flow of information between discrete plant work activities, these efforts are unlikely to alleviate the problems that have plagued traditional automation efforts—namely, data redundancies and inconsistencies, duplication of data capture efforts, changes, and information gaps. An EPRI-sponsored CAE project is developing an integrated power plant data model and guidelines for CAE applications based on this model, which will assist utilities in eliminating inefficiencies in data access and control throughout the processes of generating plants. The near-term application of this project's results is expected to result in reduced costs for operation and maintenance, and in addition, automation of design and construction activities based on the EPRI CAE guidelines will lead to reduced plant capital costs and improved quality by shortening plant construction schedules and minimizing design changes.

CAE is a development in engineering automation in which the engineering process is modeled within the computer as a progression of interrelated work functions. CAE is predicated on two main principles: (1) interactive computer programs that perform engineering activities under the direct control of an engineer; and (2) a common data base, supplying and receiving data pertinent to each activity and linking it to the other applications in the engineering process.

Computer software/system vendors and the utilities themselves are currently active in CAE development, and work in this area is proliferating. However, the trend at this point is a fragmented approach, which violates the second CAE principle. The result of this haphazard development is likely to be irregular implementation both within individual companies and among utilities and their suppliers, precluding the synergistic benefits of an integrated approach.

The EPRI guidelines project addresses the need for a systematic and consistent definition of the structure of plant information as the foundation for application of CAE to generating plants (RP2514-3). The project has four major objectives.

- To identify, investigate, and document the elements and functions constituting the information system of a plant's life cycle from plant conception to decommissioning. This objective includes detailed research of plant work activities to identify the pertinent data requirements and associated information flow paths.
- To develop an integrated plant data model, the plant information network (PIN), that represents the data and their relationships supporting the plant work activities.
- To develop guidelines for applying CAE to generating plant activities based on PIN. These guidelines will enable utility personnel to incorporate all interfaces in writing CAE hardware and software specifications.
- To promote the guidelines as the basis of an industry standard for applying CAE systems to generating plants.

In the first phase of this project, scheduled for completion in December 1986, researchers will produce the plant life-cycle data model and the guidelines.

The plant data model, PIN, is being designed in accordance with information engineering principles. It is the structure of information, in any form, that supports the discrete work activities carried on during the lifetime of the plant.

Table 2 shows the plant life cycle: site selection and plant concepts, design, construction, operation, and decommissioning. Each phase is further subdivided into areas that organize the plant functions along major disciplines, such as the primary engineering disciplines. Discrete work activities fall within each functional area. A work activity is any function performed in support of the plant. Examples of activities in the electrical functional area of the design, construction, and operation phases are cable system design, cable pulling, and electrical equipment maintenance, respectively.

Each activity has a data base that contains all information required to support that activity. When an activity begins, certain data from previous activities may be required parts of the new data base. PIN is developed by examining the data requirements for individual work activities and linking their data models together. PIN contents are determined by the combined data requirements and relationships for all plant activities.

PIN developers have identified approximately 440 activities for the five phases. Of these activities, 140 were selected for detailed

Table 2
PIN PLANT LIFE–CYCLE FUNCTIONAL AREAS

Phase	Functional Areas
Site selection and plant concepts	Financing, site selection, plant selection, vendor selection, plant concepts, licensing
Design	Civil, mechanical, electrical, environmental, quality assurance, project management, safety analysis, materials and equipment, interdiscipline design review
Construction	Project management, quality control, earthwork, structural, mechanical, electrical, instrumentation, materials control, training
Operation	Licensing/safety, training, operations control, maintenance, performance, waste management, health physics, material management, fuel management, startup, environmental monitoring, outage work planning, plant chemistry, station modifications, security, fire protection, emergency preparedness, administrative services, quality assurance/quality control, radioactive materials and waste
Decommissioning	Health physics, waste management, recommissioning, environmental monitoring, construction, planning and preparation, radioactive materials and waste, facility closeout

investigation in the initial phase of the project on the basis of the following criteria.

- The information applies to generating plants, not to the general corporation.
- The activities must be mainline generating plant activities common throughout the industry and must be applicable to the current state of plants in the industry.
- The activities must have a finite set of data that is a subset of the entire set of plant data and must provide a cross section of all applicable disciplines, functional areas, and data types.
- The activities must be key links in a continuous chain of highly interrelated activities.
- The activities selected must have potential for automation by CAE technology.

Because the initial version of PIN does not include all activities, the guidelines will contain enough information to allow utilities to add other activities that conform to the input-output boundary conditions. This flexibility will make PIN adaptable to the dynamic changes brought on by new generating technologies.

To date, researchers have investigated and documented approximately 100 plant work activities. In addition, they have developed and incorporated detailed data models for these activies into PIN. A draft report, prepared in December 1985 and available from the project manager, documents the status of the project at that time.

This report will be updated in early 1987. Utilities can use PIN and the guidelines in a number of ways. Examples of potential applications illustrate their intended roles in sound CAE development.

- To serve as a general standard for plant data exchange; to make the content, nomenclature, and format of data consistent throughout the entire plant organization
- To identify and organize complete data for any given activity; to help personnel in various areas of plant organization better understand information interfaces
- To identify the origin and complete flow path for any plant data; to optimize data flow and make work methods more efficient
- To help architect-engineers, manufacturers, and CAE suppliers respond to utility information requirements
- To help utility staff convert and customize the PIN conceptual data model to a specific data base of the utility's choice

The next phase of the project, which will be carried out in 1987–1988, will focus on utility implementation and utilization. Several utilities have indicated a desire to evaluate the guidelines for specification of CAE applications. Experts will train utility staff to develop functional specifications and customize PIN for plant-specific data. *Project Manager: John Carey*

New Contracts

Project	Funding/ Duration	Contractor/EPRI Project Manager
Advanced Power Systems		
Commercialization of the GATE Code (RP2052-7)	$159,100 24 months	Expert-Ease Systems, Inc./*A. Cohn*
Data Acquisition System Development for Field Test of Gas Turbine Diagnostic Instruments (RP2102-16)	$172,500 6 months	Systems Integrated/ *L. Angello*
Coproduction of CO_2 and Electricity in a Coal Gasification–Combined-Cycle Power Plant (RP2221-16)	$100,000 8 months	Fluor Technology, Inc./ *B. Louks*
Evaluation of Superalloy Single Crystals (RP2382-5)	$13,200 7½ months	Southwest Research Institute/*C. Knauf*
Evaluation of Superalloy Single Crystals (RP2426-11)	$110,800 12½ months	Southwest Research Institute/*C. Knauf*
Coal Combustion Systems		
In-duct Spray Drying: Proof-of-Concept Tests (RP982-39)	$77,300 7 months	Radian Corp./*R. Rhudy*
Cycling Conversion Study at Public Service Electric & Gas Co.'s Hudson Unit 2 (RP1184-16)	$901,700 19 months	PSE&G Research Corp./ *A. Armor*
Test Plan and Procedures for Measuring Impacts of Coal Quality on Power Plant Equipment (RP1891-3)	$200,000 8 months	Energy and Environmental Research Corp./*A. Mehta*
Electrical Systems		
Transmission Line Digital Protective Relaying Devices: Demonstration and Evaluation (RP1359-13)	$507,600 23 months	General Electric Co./ *S. Wright*
EMTP Field Test Comparisons (RP2149-5)	$205,100 16 months	General Electric Co./ *J. Mitsche*
Economic Improvements of Static VAR Control Operation (RP2707-2)	$50,000 8 months	University of Wisconsin at Madison/*J. Marks*
Improved Load-Tap-Changing Equipment for Power Transformers and Regulators: Feasibility Study (RP2763-1)	$109,800 19 months	Westinghouse Electric Corp./*D. Johnson*
Improved Load-Tap-Changing Equipment for Power Transformers and Regulators: Feasibility Study (RP2763-2)	$101,600 12 months	McGraw-Edison Co., Power Systems Div./ *D. Johnson*
Circulating-Current-Loss Analysis (RP2839-1)	$42,000 8 months	David A. Silver & Associates, Inc./*H. Songster*
Energy Management and Utilization		
Quantifying the Dynamic and Operating Benefits of Storage Technologies (RP1084-22)	$90,500 7 months	Electric Power Consulting, Inc./*D. Rigney*
Development of a Hybrid Breaker–Remote Switch (RP2568-5)	$23,100 7 months	Matsushita Electric Works, Ltd./*L. Carmichael*

Project	Funding/ Duration	Contractor/EPRI Project Manager
Metal-Melting Applications for Industry (RP2787-1)	$2,700,000 24 months	Carnegie-Mellon University/*L. Harry*
Commercial Unitary Heat Pump Improvement Targets (RP2792-6)	$37,500 4 months	Ducker Research Co., Inc./*M. Blatt*
Environment		
Hormetic and Harmful Effects of Radiation on Immunity (RP8000-8)	$58,100 7 months	University of California at Los Angeles/*L. Sagan*
Nuclear Power		
Exploratory Studies on Concrete Interactions and Fission-Product Releases (RP2136-3)	$45,000 6 months	Science Applications International Corp./ *R. Ritzman*
Assessment of 10CFR61 Impact on the Nuclear Industry (RP2412-6)	$75,000 2 months	Vance and Associates/ *P. Robinson*
De Minimus Waste Determination of Candidate Wastes by Using IMPACTS Methodology (RP2412-8)	$53,000 2 months	General Physics Corp./ *P. Robinson*
Technical Data Requirements for Plant Maintenance and Operations (RP2513-4)	$104,800 4 months	Reedy Associates/ *W. Bilanin*
Monticello Radiation Control Loop Studies (RP2549-11)	$310,000 58 months	Radiological and Chemical Technology, Inc./ *H. Ocken*
Assessment of Tectonic Stress Around Seismic Sources (RP2556-24)	$187,000 38 months	Pennsylvania State University/*C. Stepp*
In Situ Cable Aging Assessment Methodology (RP2643-10)	$108,000 16 months	Franklin Research Center/ *G. Sliter*
BWR Zinc Injection Demonstration (RP2758-1)	$543,300 67 months	General Electric Co./ *C. Wood*
LACE Aerosol Code Benchmarking (RP2802-7)	$85,000 7 months	Rockwell International Corp./*F. Rahn*
R&D Staff		
On-line Corrosion Rate Monitoring in a Cyclic Reheat System (RP1871-17)	$108,000 7 months	Corrosion and Protection Centre Industrial Services, UMIST/*B. Syrett*
Enhanced Sulfidation Resistance of Fe, Ni, and Co Alloys by Alloying With Mo and Nb (RP2278-5)	$185,300 31 months	University of California at Los Angeles/*J. Stringer*
Metal-Wire-Reinforced Ceramic Composites (RP2706-2)	$41,000 6 months	AMERCOM, Inc./ *W. Bakker*
Erosion of Fluidized-Bed Combustion Tube Materials (RP8000-6)	$70,000 9 months	Lawrence Berkeley Laboratory/ *J. Stringer*
Natural Convection Melting and Solidification (RP8006-4)	$93,000 25½ months	Duke University/ *J. Kim*

New Technical Reports

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

ADVANCED POWER SYSTEMS

Utility Considerations for Wind Energy Purchase Agreements
AP-4591 Final Report (RP1996-2); $25
Contractor: R. Lynette & Associates, Inc.
EPRI Project Manager: F. Goodman

Performance of the Vanguard Solar Dish–Stirling Engine Module
AP-4608 Final Report (RP2003-5); $40
Contractor: Energy Technology Engineering Center
EPRI Project Managers: R. Taylor, J. Schaefer

Coproduction of Peaking Fuels in IGCC Power Plants: Process-Screening Study
AP-4657 Final Report (RP2111-2); $47.50
Contractor: Air Products and Chemicals, Inc.
EPRI Project Manager: N. Hertz

System Expansion Analysis: Comparison of Conventional Coal and British Gas Corp./Lurgi Gasification–Combined-Cycle Power Plants
AP-4673 Final Report (RP2029-11); $25
Contractor: Zaininger Engineering Co.
EPRI Project Manager: B. Louks

Proceedings: Fifth Annual EPRI Contractors' Conference on Coal Gasification
AP-4680 Proceedings (RP1654); $55
EPRI Project Manager: N. Holt

COAL COMBUSTION SYSTEMS

Dissimilar-Weld Failure Analysis and Development: Comparative Behavior of Similar and Dissimilar Welds
CS-4666 Final Report (RP1874-2); $25
Contractor: General Electric Co.
EPRI Project Manager: R. Viswanathan

Workshop Proceedings: Life Assessment and Repair of Steam Turbine Casings
CS-4676-SR Proceedings; $165
EPRI Project Manager: R. Viswanathan

Remaining-Life Estimation of Boiler Pressure Parts: Crack Growth Studies
CS-4688 Final Report (RP2253-7); $100
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: R. Viswanathan

Effects of SO_2 Scrubber Environments on Alloy Corrosion
CS-4697 Final Report (RP1871-6); $32.50
Contractor: Battelle, Columbus Laboratories
EPRI Project Manager: B. Syrett

FGD Maintenance Guidelines
CS-4699 Final Report (RP1872-4); Vol. 1, $40; Vol. 2, $40
Contractor: Stone & Webster Engineering Corp.
EPRI Project Manager: R. Moser

Microstructure and Texture Effects on Titanium Alloys
CS-4727 Interim Report (RP1266-33); $25
Contractor: Technische Universität Hamburg-Harburg
EPRI Project Manager: R. Jaffee

ELECTRICAL SYSTEMS

Development of an SF_6 High-Voltage DC Circuit Breaker
EL-4388 Final Report (RP1507-2); $32.50
Contractor: Westinghouse Electric Corp.
EPRI Project Manager: J. Porter

Advanced Power System Security Analysis Concepts
EL-4522 Final Report (RP1999-1); Vol. 1, $25; Vol. 2, $25
Contractor: Michigan State University
EPRI Project Manager: J. Mitsche

TLWorkstation Code: Version 1.0
EL-4540-CCM Computer Code Manual (RP1280, RP1284-3, RP2151-1); Vol. 1, $25; Vol. 5, $40; Vol. 6, $55; Vol. 17, $25; Vol. 18, $25
EPRI Project Manager: R. Kennon

Integrated Power System Analysis Package: Scoping Study
EL-4632 Final Report (RP2550-1); Vol. 1, $32.50; Vol. 2, forthcoming
Contractor: Carlsen and Fink Associates, Inc.
EPRI Project Manager: J. Lamont

Power Flow Calculations Utilizing Array Processors
EL-4642 Final Report (RP1710-1); $32.50
Contractor: Boeing Computer Services Co.
EPRI Project Manager: J. Lamont

ENERGY MANAGEMENT AND UTILIZATION

Electroforming of Metals: State-of-the-Art Assessment
EM-4568 Final Report (RP2478-1); $25
Contractor: Battelle, Columbus Division
EPRI Project Manager: L. Harry

Ultrahigh-Head Pump/Turbine Development Program
EM-4599 Final Report (RP2039-1); Vol. 1, $55; Vols. 2–8, forthcoming
Contractor: Hitachi Works
EPRI Project Manager: A. Ferreira

Consumer Preferences for Electric Vehicles
EM-4634 Final Report (RP1145-2); $32.50
Contractor: University of California at Berkeley
EPRI Project Manager: C. Gellings

Energy Consumption in the Transportation Services Sector
EM-4636 Final Report (RP757); $32.50
Contractor: Wharton EFA, Inc.
EPRI Project Manager: C. Gellings

ENVIRONMENT

Subregional Cooperative Electric Utility, Department of Defense, National Park Service, and EPA Study (SCENES) on Visibility: Overview
EA-4664-SR Special Report; $25
EPRI Project Manager: P. Mueller

Estimating the Cost of Uncertainty in Air Quality Modeling
EA-4707 Final Report (RP2309-1); $32.50
Contractor: Brookhaven National Laboratory
EPRI Project Manager: A. Silvers

NUCLEAR POWER

WAM-E User's Manual
NP-4460-CCM Computer Code Manual (RP2507-1); $55
Contractor: Science Applications International Corp.
EPRI Project Manager: J. Gaertner

Reactor Analysis Support Package (RASP)
NP-4498 Final Report (RP1761); Vol. 1, $55; Vol. 2, $1000; Vol. 3, $1000
Contractors: S. Levy, Inc.; Energy Incorporated; Nuclear Project, Inc.; Combustion Engineering, Inc.
EPRI Project Manager: L. Agee

Condensate Polishers for Brackish Water–Cooled PWRs
NP-4550 Topical Report (RP1571-5); $40
Contractors: Central Electricity Generating Board; Gibbs & Hill, Inc.; NWT, Inc.
EPRI Project Manager: T. Passell

Condenser Improvements for PWRs
NP-4551 Topical Report (RP1571-5); $25
Contractor: Gibbs & Hill, Inc.
EPRI Project Manager: T. Passell

Deaeration of Makeup Water for LWRs
NP-4552 Topical Report (RP1571-5); $25
Contractor: Gibbs & Hill, Inc.
EPRI Project Manager: T. Passell

ELECTRIC POWER RESEARCH INSTITUTE
Post Office Box 10412, Palo Alto, California 94303

NONPROFIT ORGANIZATION
U.S. POSTAGE
PAID
PERMIT NUMBER 60
SUNNYVALE, CALIFORNIA

October 1986

EPRI JOURNAL

ADDRESS CORRECTION REQUESTED