Plugging in New Technologies

ELECTRIC POWER RESEARCH INSTITUTE

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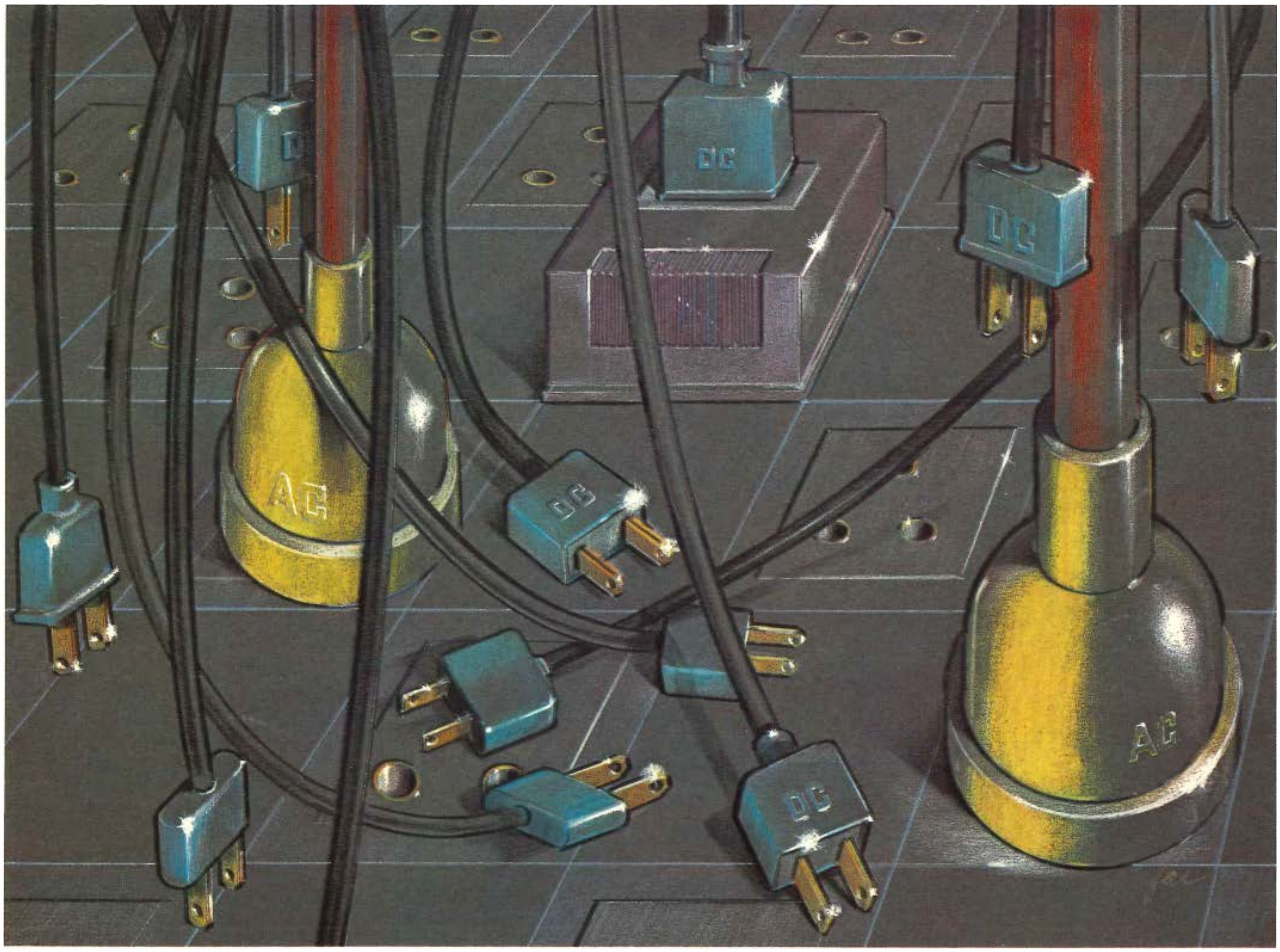

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Cover: Research is needed in dc-to-ac power conditioning, generation planning, operation, and control before new energy technologies can deliver electricity to customers.

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Integrating New Sources Into Utility Systems

The decade of the 1980s seems destined to deliver on a promise of the 1970s: the appearance of unconventional, relatively small-scale, dispersed electricity generation. A 4.8-MW fuel cell power plant being started up in New York City may be the forerunner of 10-MW systems that will begin to see utility service within the decade. A major test facility in New Jersey is preparing to try out new battery energy storage systems that may become commercially available by the end of the 1980s. Many utilities are encouraging the installation of megawatt-size cogeneration facilities. Generation from small hydroelectric installations and wind turbines is attracting growing interest. Further ahead, perhaps in the 1990s, photovoltaic generation may become a reality. Even as some of these new technologies are being developed, utilities are anticipating their contribution to electricity networks. Southern California Edison Co., for example, is planning to add up to 2000 MW to its capacity by 1990 through a combination of wind, hydro, cogeneration, fuel cell, geothermal, and solar power. The New England Electric System expects to derive about one billion (10^9) kWh a year by 2000 from small wood, wind, solid waste, hydro, and cogeneration plants. Plainly, power generation on the megawatt scale and smaller will soon be seen on utility networks.

One fundamental difference between these new electricity sources and conventional power plants is that the new sources will be sited in multiple dispersed locations. This raises new questions for utilities accustomed to operating large central power stations. How should these new sources supply electricity to the user? Should each of these sources serve a limited number of users directly, or should they be connected to the electricity network? If megawatt-scale and smaller sources are to become part of electric utilities, what technical and institutional issues must be resolved to pave the way for their integration into gigawatt-scale electricity networks?

One important question—whether electricity sources should stand alone or be connected to the network—has already been answered by the results of several economic and system studies. Wherever a suitable electricity network exists in an area, it is advantageous to connect new energy sources to the network. Only in this way can a reliable supply of power be ensured without expensive backup power generation or energy storage. Equally important, network connection allows a large number of users to share the output from the new sources, guaranteeing fullest use.

This month's cover story discusses how a diverse group of new electricity sources can be integrated cost-effectively and safely into electric utility networks. Some of the integration issues are primarily technical. For fuel cells, storage batteries, and photovoltaic arrays, utilities will need a technology that can convert direct current efficiently and economically to utility-quality alternating current and do so on a relatively small scale. Much has been accomplished in this area during the past 10 years. For alternating current wind and hydro generation, the issue is more how utilities should allow for predictable and unpredictable fluctuations in the power output of these sources on their networks. Considerable progress has been made here, too.

There are several other significant issues to be considered in the introduction of all these new sources of electricity: prominent among them are safety, ownership, and financing. Although safety presents some novel considerations, we can be reasonably certain that application of modern communications and control techniques will permit dispersed power sources to be started, operated, and shut down safely when necessary. But private financing and ownership, feasible because of the relatively small size of projects and attractive because of possible tax credits, can present utilities with a dilemma. Many utilities will welcome some relief from making investments in generating capacity. Other utilities will find that current laws, particularly PURPA, could force them to buy privately generated power at relatively high cost. Strict application of PURPA would tend to give private generators all the benefits of network integration but could leave utilities with most of the risks of privately operated, small new sources of electricity, such as potentially inadequate control and reliability. It seems only fair that the economic benefits from new sources should be shared whenever utilities provide private generators with the economically decisive benefits of integration: a backup power supply, which eliminates the need for costly on-site redundancy and/or storage, and an energy sink, which maximizes the use of private generating equipment (and hence its profits).

Although several issues remain to be resolved, it is apparent that small dispersed sources of electricity are converging on utility systems. As utilities install these sources themselves or accept the electricity from privately owned sources, we are reminded of the days when utility systems were made up of small local generators. In the decades since then, utilities have built the efficient and economic networks that we now depend on. And today these networks permit the most economic use of small new sources. Rather than the sometimes-predicted competition between large and small, hard and soft technologies, we will be seeing a true synthesis for the benefit of both the suppliers and the users of electric power.

Fritz R. Kalhammer, Director
Energy Management and Utilization Division

Authors and Articles

New Connections for New Technologies (page 6) surveys ways for utilities to integrate new technologies into the existing utility network. Nadine Lihach, *Journal* feature writer, points out that many new technologies produce dc power instead of ac, which utility systems and customer appliances are designed for. They may generate power from small dispersed plants instead of large centralized ones. They may generate power intermittently. They may even be privately owned and their power sold to utilities for distribution. Planning for this integration involves people in several EPRI research programs, and Ralph Ferraro is particularly concerned that utilities be ready with new total energy delivery systems.

Ferraro is technical manager for electric interface and control systems in the Energy Management and Utilization Division. His R&D relates to utility fuel cells, load-leveling batteries, photovoltaic energy conversion, and MHD power generation. Ferraro has worked in power conversion and control for nearly 25 years, specializing in utility applications since 1973. He joined EPRI in December 1977 after four years as control systems engineering supervisor for Bechtel Power Corp. Ferraro is an electrical engineering graduate of the Newark College of Engineering.

■

Amorphous Metals: Cutting Losses in the Core (page 14) is a case study in electrical materials development. Science writer John Douglas explains how amorphous steel cores can dramatically reduce the energy lost in utility transformers. Can these transformers be built and operated for less than the cost of the avoided losses? Edward Norton manages EPRI R&D projects that have developed metallic glass and are producing experimental transformers that will come up with the answer.

A member of the Electrical Systems Division technical staff since January 1975, Norton has worked in the development, design, application, and marketing of transformers for 28 years. He was formerly manager of power transformer applications with Allis-Chalmers Corp. Norton earned a BS in electrical engineering at the Polytechnic Institute of Brooklyn.

■

Trade-offs in NO_x Control (page 18) reports from two fronts in the R&D campaign against power plant emissions of nitrogen oxides (NO_x). Ralph Whitaker, *Journal* feature editor, writes of measures to inhibit NO_x formation when coal burns, as well as to remove it from combustion exhaust gases. Michael McElroy and Michael Miller of EPRI's Coal Combustion Systems Division are instrumental in managing the R&D and gauging the performance of new technologies.

McElroy has been with EPRI since October 1976. As a project manager for NO_x control in the Air Quality Control Program, he builds on a specialization begun when he was with KVB, Inc. Much of his four years with that company was spent in field measurements of NO_x emissions from utility boilers and the design of operating routines to reduce NO_x levels. McElroy developed emission analysis systems while he was a graduate student at the University of California at Berkeley, where he earned BS and MS degrees in mechanical engineering.

Michael Miller is technical manager for environmental assessment in the Environmental Control Systems Department. He came to EPRI in April 1980 after two years with Pacific Gas and Electric Co., where he was administrative assistant to the vice president for planning and research. Before that he was an environmental analyst for URS/John A. Blume & Associates, Engineers and an air quality analyst for Northern States Power Co. Miller has a BS in zoology and an MS in environmental studies from the University of Wisconsin and an MS in public health from the University of Minnesota.

Traditionally the January/February *EPRI Journal* has been a review of the previous year's research. Beginning this year, it will be a conventional issue. A review of 1981 research will be included in EPRI's *1981 Annual Report*, which will be published by the *Journal* and sent to its subscribers in lieu of a regular April issue.

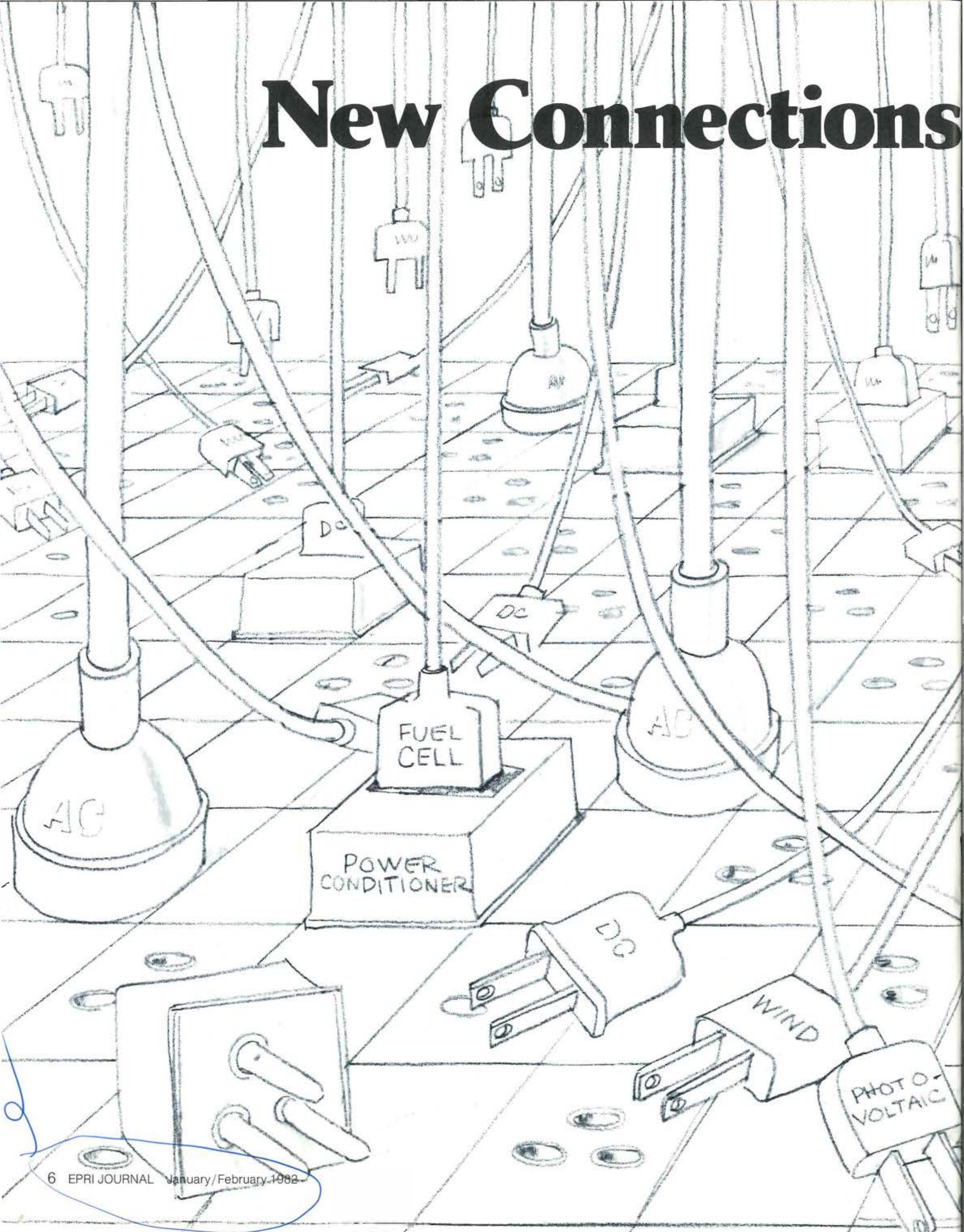

Ferraro


Norton

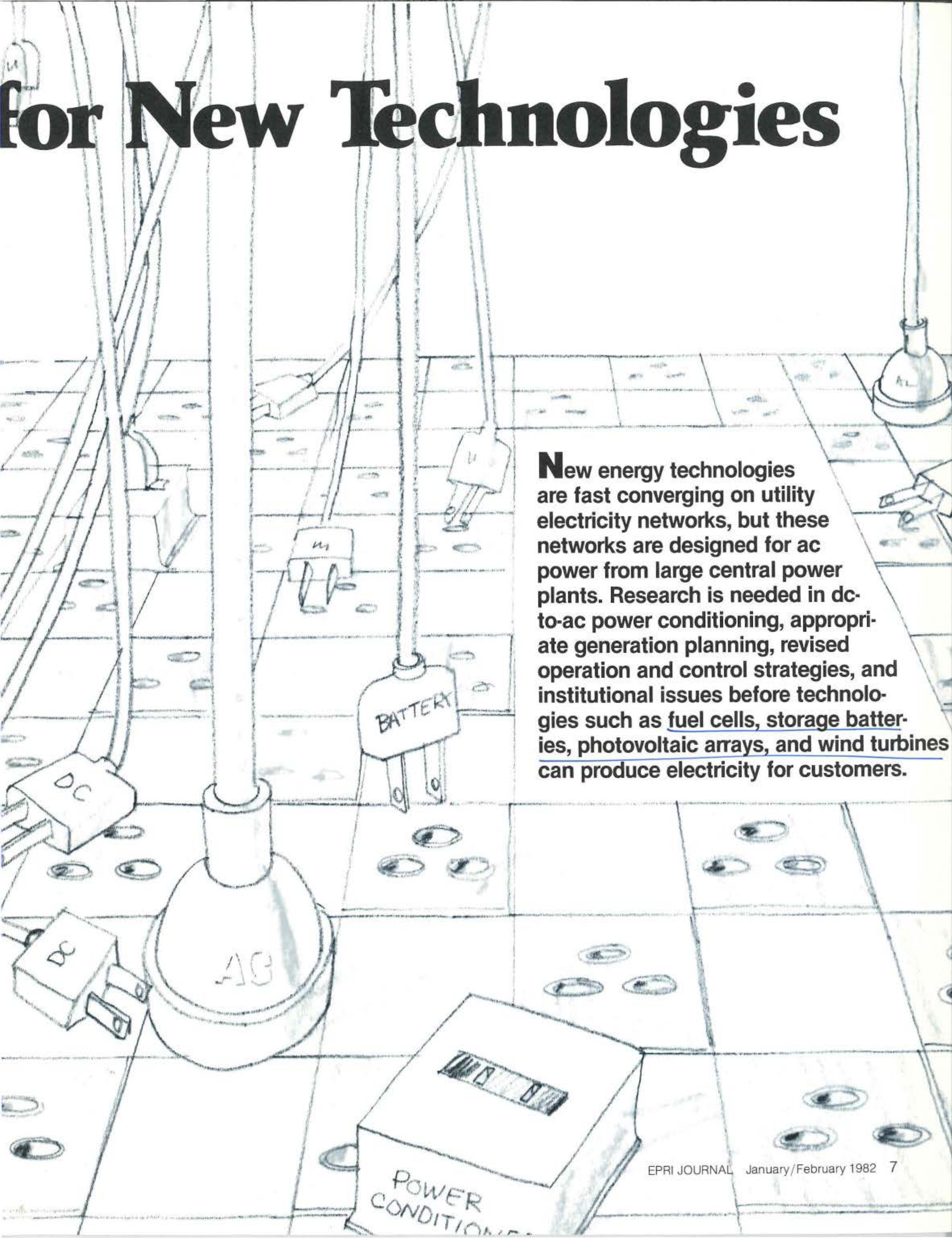

McElroy


Miller

New Connections



for New Technologies



New energy technologies are fast converging on utility electricity networks, but these networks are designed for ac power from large central power plants. Research is needed in dc-to-ac power conditioning, appropriate generation planning, revised operation and control strategies, and institutional issues before technologies such as fuel cells, storage batteries, photovoltaic arrays, and wind turbines can produce electricity for customers.

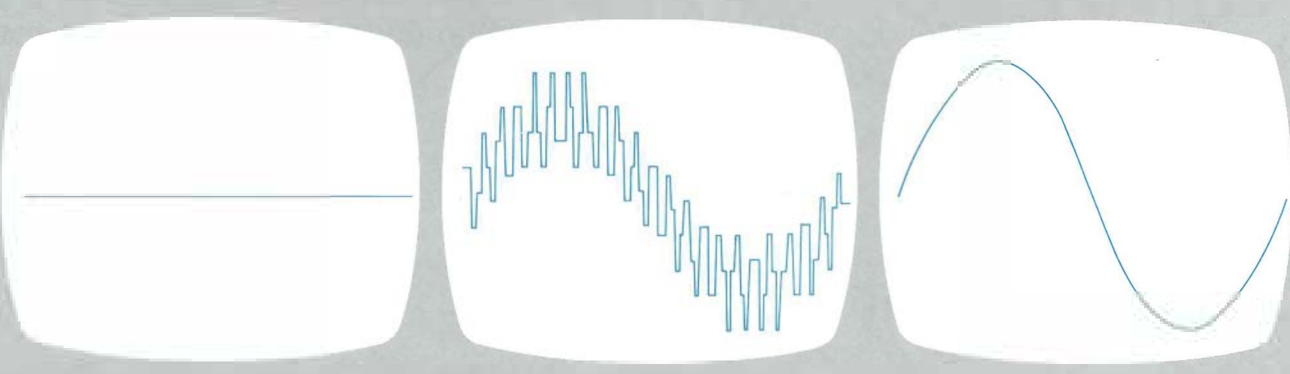
When fuel cells, storage batteries, photovoltaic arrays, and wind turbines begin to come on-line later this decade, a new electricity will be in town. Fuel cells, batteries, photovoltaic arrays, and many small wind turbines will produce direct current (dc) electricity, not the alternating current (ac) that utility systems and customer appliances are designed for. Solar and wind are intermittent and cannot be summoned by stoking a coal boiler or firing a gas turbine. Many of the new technologies will generate power from small dispersed plants instead of from large central power stations. Some of the plants may even be privately owned, and the electricity they produce sold to utilities. In short, these new energy technologies will be different in important ways from the coal, oil, gas, and nuclear technologies that preceded them. If these new technologies are to provide electricity in the future, plans for their integration into the existing utility network have to be made now.

Until recently, the integration of new energy technologies into the existing network was of little concern to utilities. The new technologies had to be developed first; integration issues—and some planners were not convinced there were any—could be resolved later. But new technologies are approaching commercialization, and many integration questions remain unresolved. Ralph Ferraro, technical manager for electric interface and control systems in EPRI's Energy Management and Utilization Division, is particularly concerned that utilities begin to think in terms of total energy delivery systems as they prepare for these new technologies. For total energy delivery, utilities must consider not only new power-generation technologies but also technologies to convert raw dc output to usable ac; planning methodologies to incorporate new technologies into future generation systems; operation and control strategies appropriate for dispersed generation; and answers to perplexing institutional questions.

Shaping dc power

A critical aspect of total energy delivery is the conversion into usable ac power of the dc power that fuel cells, batteries, photovoltaic cells, and many small wind turbines produce. Conversion is absolutely necessary because the nation's electricity systems are based on ac power. Customer equipment—refrigerators, washing machines, air conditioners, water heaters, hair dryers, power tools—uses only ac.

Inverters and converters that can



If power conditioning could be viewed through an oscilloscope, the process would look something like this. The dc electricity (left) is the raw output of fuel cells, storage batteries, photovoltaic arrays, and many small wind turbines. Inside advanced power-conditioning systems, thyristors are switched off and on to approximate an ac waveform (center). The electricity is then further refined to the ac form (right) that utility systems and customer appliances are designed for.

switch dc power to ac are available from manufacturers today, but they are not the equipment that utilities will be buying for the technologies of the impending future. Some of these off-the-shelf inverters and converters are relatively unsophisticated rotating equipment, whose moving parts, high maintenance requirements, short service life, and low efficiencies have a diminishing place in the utility network. Other inverters and converters are modern solid-state equipment, but even they may not be ideal for utility service. They can produce ac electricity warped by harmonics, generate electromagnetic interference, and cause other electrical distortions. All this, in turn, can consume useful power, interfere with proper functioning of the electricity grid (especially power line communications systems), and even damage customer equipment.

More advanced equipment, known as power conditioning systems (PCSs), could go beyond rudimentary dc-to-ac conversion and revamp the resultant ac waves into the power required by utilities and their customers. Such PCSs are now used for high-voltage dc (HVDC) transmission and for uninterruptible dc power sources (such as battery or diesel-powered generators that keep computers at banks, airports, and military installations operating during power outages). But HVDC PCSs are designed to handle power in the range of 100–600 kV at 500–2000 MW, and uninterruptible power sources are designed for a mere 250–500 V at 100 kW. Neither of these approaches is technically or economically suited for the problem of connecting, say, a 3–4-kV, 10-MW fuel cell plant with the electric network.

Utilities will need entirely new PCS designs for new technologies. Unfortunately, the understanding of power quality now on utility lines is so sketchy, and the new technologies are so novel, that performance specifications for PCSs are ill-defined. Yet Ferraro emphasizes that at least interim guidelines for PCSs need to be developed now so that researchers, developers, and manufacturers can have a target for designing and building early systems.

Efforts by EPRI and DOE to develop PCS specifications, designs, and hardware have been under way since the early 1970s. The attempts were first directed at fuel cells and then batteries. EPRI financed a number of PCS design studies to identify technical issues. Later, a study by Westinghouse Electric Corp. summarized the state of the art of inverters and converters and concluded that further work would have to be done to improve PCS efficiencies and lower PCS costs. Not long after, United Technologies Corp. was selected to develop an improved design for an ac/dc power converter for use with both fuel cells and batteries.

While specifications and designs for the PCSs of the future were being developed, early PCS hardware was being built for use at key test facilities. A PCS was built in 1976 for a 1-MW fuel cell test plant funded by United Technologies and nine utilities. Later, a PCS was constructed for the EPRI–DOE 4.8-MW fuel cell demonstration on the grid of Consolidated Edison Co. of New York, Inc. The latter equipment, which incorporates some of the earlier concepts reported in EPRI and DOE studies, is now undergoing startup testing.

A 2.5-MW PCS built by AiResearch Manufacturing Co. of California serves the Battery Energy Storage Test (BEST) Facility, Hillsborough Township, New Jersey, and a 3.5-MW PCS built by Westinghouse was installed at the magnetohydrodynamics (MHD) development facility in Butte, Montana. (EPRI, DOE, and New Jersey's Public Service Electric and Gas Co. built and are now operating the BEST Facility; DOE built the MHD facility, with The Montana Power Co. as host, and EPRI supplied the PCS.) These facilities were built primarily to test batteries and MHD (another new dc generating source) rather than PCSs, so they use conventional, state-of-the-art PCSs rather than advanced concepts. Nevertheless, they will provide a good data base on PCS needs, and the BEST Facility has provisions to test advanced PCSs.

Today, EPRI and DOE are cooperating in the design of a 10-MW PCS for fuel cells and batteries that embodies all the improvements that have been developed in recent years: better semiconductors and microprocessors, advanced mechanical packaging and cooling technologies, lower cost, smaller size, and enhanced efficiencies. Many of the research results will be applicable to PCSs for photovoltaics, wind, and even MHD. The results will be useful not only to utilities but also to other PCS users in the residential, industrial, and commercial sectors.

Meanwhile, DOE is concluding an extensive program to develop a group of PCS designs for small and medium generation sources. DOE's designs for the 5–10-kW range can link small residential generation sources to the utility network; designs for the 150–200-kW range are for intermediate industrial and commercial generation sources. These designs are for photovoltaic systems, but the results may be applied to small wind, fuel cell, and battery storage installations as well. (EPRI has worked with DOE in an advisory capacity on this project.) Several prototype PCSs for residential photovoltaic systems will probably be built over the coming year.

PCS requirements

PCSs are complicated solid-state equipment, and a considerable amount of further research will have to be done to identify PCS specifications and then design systems that meet those specifications. One critical requirement is an acceptably low level of harmonic currents. The preferred waveform for utility and customer equipment is smooth, sinusoidal 60-Hz ac (i.e., the ac makes 60 complete sine-shaped cycles per second). However, power conversion equipment sometimes produces a waveform that includes multiples of 60 cycles—for example, 180, 300, or 420 cycles. These multiples are called harmonics; harmonic currents cause harmonic voltages, and when they clash with utility distribution voltages, jagged waveforms are produced. Excessive harmonic voltages can cause increased electrical losses as well as overheating in utility and customer equipment such as motors, transformers, switchgear, and fuses. The electrical losses cost money, and the overheating can shorten equipment life. Excessive harmonics can also interfere with dispatch control, protection systems, and metering. Because reliable data on the effects of low-quality power are lacking, EPRI is now reviewing existing power-quality data and is considering a more definitive study in that area.

PCSs can be built to suppress harmonics, but unfortunately, present methods focus on specific harmonics. For example, filters made up of inductors and capacitors to eliminate irregular harmonic currents must be fine-tuned to nullify a specific harmonic. If the harmonic is constantly fluctuating, as it might be on a utility line, the cost of the filter increases, as does its size and weight. Another technique for eliminating unwanted harmonics introduces electric phase shifts that effectively cancel harmonic waves. The phase shifts are formed with the help of specially designed transformers, and, like filters, this is a very specific and costly solution.

A more general, and hence less expensive, solution to harmonics may be wave-shaping. Unlike filters or special cancellation transformers, which correct an existing undesirable harmonic, waveshaping is the exacting electronic construction of desirable waveforms within the power conditioner. This reduces the need for costly, heavy capacitors and special transformers and eliminates the need to make special adjustments at each site. As part of its design project on the 10-MW PCS, EPRI has commissioned construction of prototype hardware to verify the wave-shaping concept.

Another requirement for PCSs is that they must not generate excessive electromagnetic interference (EMI). EMI is actually high-frequency harmonics produced by using high-speed switching devices, such as thyristors, in the conversion from dc to ac power. EMI can interfere with telephone, television, and radio transmissions, and it also has the potential to limit future applications of the utility communications and control equipment that is being developed for load management.

EMI generation is a problem not only with PCSs but also with calculators, microwave ovens, CB radios, and other electronic equipment, and the Federal Communications Commission has issued EMI standards that include standards for PCSs. But as increasing amounts of electronic equipment that use semiconductor switching are plugged into utility lines, the potential EMI problems increase. Thus, the most effective way of dealing with EMI is to prevent its being generated at the source, and techniques that include wiring, shielding, filtering, and mechanical design are used in some PCS designs to directly suppress the phenomenon.

PCSs for utility service must also have acceptable power factor characteristics to maintain service voltage. Typical utility loads have a power factor that corresponds to a load current that slightly lags behind supply voltage. Because of this lagging current, as well as the series reactance of utility lines, power factor correction capacitors must be incorporated into the distribution system.

With the advent of new dc sources on utility systems, it is possible that improperly designed PCS equipment could consume significant amounts of reactive power. Consequently, a utility might have to install additional correction hardware. Increased line losses could also result from higher reactive current levels, and oversized distribution components might be required to handle additional reactive power. Because of the potential cost and technical impacts of low power factors on the distribution system, power factor correction may have to be included in PCSs.

Still another requirement for utility-compatible PCSs is adequate electrical protection. If ac distribution lines malfunction (through a short circuit, for example), the PCS must be able to shield a dc generating source, such as a storage battery, from that malfunction. Conversely, if the dc source malfunctions, the PCS must protect the ac lines from harm. And if malfunctions arise in the PCS itself, measures must be taken to prevent adverse effects on adjacent dc source and ac lines. This protection must be built into the PCS to protect both utility and customer investments.

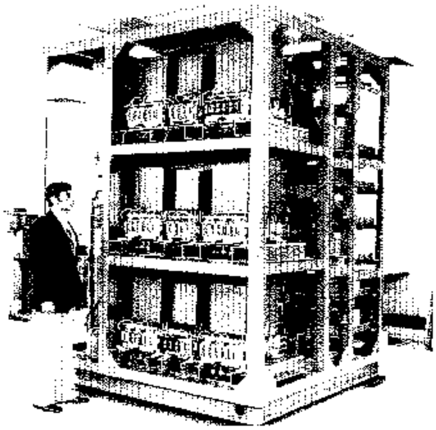
Besides harmonics, EMI, power factor, and protection specifications, PCSs must also meet some more-conventional requirements if they are to serve new technologies effectively. For instance, PCSs must produce ac power efficiently over the wide range of voltage levels at which new technologies will be operated. (The voltages of power generated by fuel cells and storage batteries vary, depending on equipment operating mode. Photovoltaic and wind power voltages also fluctuate, depending on the availability and strength of sunshine and wind.)

Large PCSs must also be modular, rugged, and flexible enough to be sited in a variety of outdoor environments with minimal modification. This will save the cost of redesigning and altering equipment to adapt to changes in altitude, humidity, precipitation, temperature, wind, and airborne pollutants, as well as varying generation, transmission, and distribution parameters. It will also keep manufacturing and maintenance costs down.

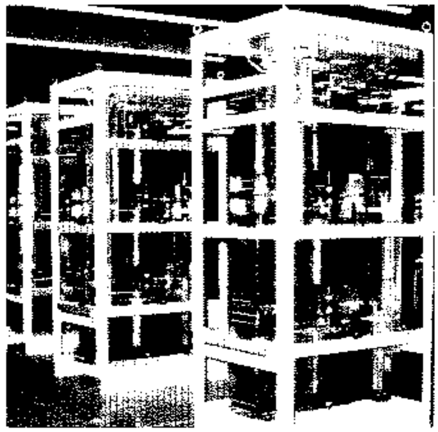
Low cost and long life are basic requirements for PCSs. An early goal was a cost of no more than $88/kW (1980 dollars) for a PCS rated at 10 MW and a life of 20 years, with nominal maintenance and repair. (This selling price assumed production quantities of 150 units a year.) A PCS with recent design improvements is now projected to cost $60–$70/kW; if advances in electronics

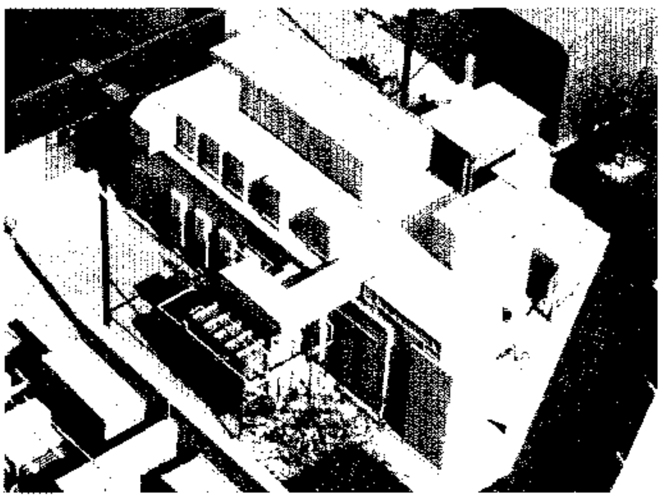
The change from dc to ac power is complicated, and different power-conditioning systems will have to be developed for different technologies. This is how one power-conditioning system, that of the 4.8-MW fuel cell demonstration in New York City, will do it.

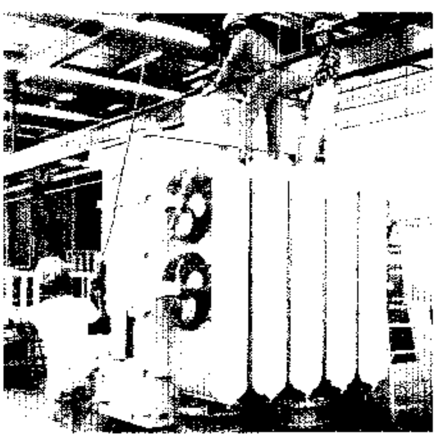
The dc power from fuel cells is first routed through converter bridges, where a rudimentary conversion to ac power takes place.



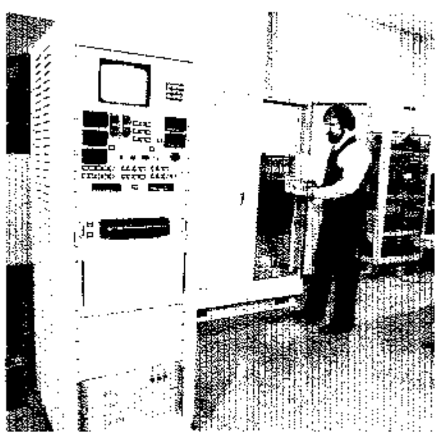
The ac power next goes through low-voltage series reactors and harmonic cancellation transformers to be shaped to a more desirable waveform.







At the main transformer, the voltage of the outgoing ac power is stepped up to match the voltage on the utility's grid.



Control and diagnostic units oversee the entire conversion process.

continue, the price might drop to about \$50/kW by the end of the decade. The small PCSs being developed by DOE for residential and industrial use will have a higher cost: early results indicate that a mass-produced residential-size PCS of 10 kW will cost \$180–\$300/kW; an industrial-size PCS of about 500 kW will cost \$70–\$100/kW.

Beyond PCSs

Even superbly designed power conditioning systems cannot provide total energy delivery by themselves. Overall utility planning will have to change to accommodate new technologies, both dc and ac. These planning modifications are just as necessary as PCSs to integrate the new technologies effectively into utility networks.

Utilities typically plan about 10 years ahead for new generating equipment, transmission and distribution equipment, and fuel supply. They use established planning methods for figuring the fuel and capacity contributions (or credits) of coal, oil, gas, and nuclear plants. These conventional plants can be conveniently dispatched as needed, and planning for their availability to generate power is reasonably dependable. Yet some of the new technologies cannot always be marshaled to meet demand. Wind and sun may not be available when power is needed, such as when a photovoltaic system winks out just as early-evening electricity demand picks up. Conversely, wind and sun may be abundant when power is not needed—for example, during periods already adequately served by efficient baseload plants. Wind turbines or photovoltaic arrays are not always the best technologies for these situations.

Because the conventional planning methodologies that work for coal, oil, gas, and nuclear do not take intermittent new resources into account, these will have to be modified to work with sun and wind power. EPRI's Advanced Power Systems Division has developed preliminary ways to estimate both fuel

– screen to identify box
– reduce box size

PCSs FOR TRADITIONAL PLANTS, TOO

Coal, oil, and gas plants may benefit by using power conditioning systems to convert the constant-speed motors that drive plant fans to variable-speed motors.

Fuel cells, storage batteries, photovoltaic arrays, and wind turbines are not the only energy technologies that could benefit from power conditioning systems (PCSs). Coal, oil, and gas plants might also profit from PCSs, used in a different capacity.

To understand the potential benefits, one must first understand a specific area of power plant operation. Air is needed for combustion at coal, oil, and gas plants; this air is forced into boilers by draft fans, which are powered by motors, which in turn may be powered by electricity directly from a plant bus. The voltage to the motor drive system never changes, so the fan's speed is constant. Yet because of plant duty cycles, combustion does not always require the same airflow. A system of dampers throttles the airflow from the fan to match plant load.

The catch is that these 5000–10,000 horsepower draft fans gobble up about 5–10 MW of the plant's electricity output. If an appropriate PCS could be installed between the power bus and the motor drive to control the speed of the fan, the utility could save perhaps 30–50% of the energy that the fan systems currently use.

To prove it, EPRI has recently commissioned UTC and Bechtel Power Corp. to evaluate a PCS retrofit design for constant-speed fans at a Southern California Edison Co. plant. Because PCSs for the utility industry are still under development, the evaluation will use a prototype PCS designed for fuel cells and batteries. The contractors will compare the capital and operating costs of the variable-speed motor drive with those of the constant-speed motor drive already in the plant. Application of the variable-speed drive to a new plant will also be considered. The study will be completed this spring.

Of course, all plants have different cycling characteristics, so the economics of a variable-speed motor drive will vary from plant to plant. But Ralph Ferraro strongly suspects that a variable-speed drive in the right plant could save a utility enough money to pay for the PCS in just a few years. There may be savings not only in electricity but also in wear and tear on auxiliary plant equipment. Should the study confirm Ferraro's suspicions, EPRI may consider demonstrating the design on an existing power plant.

Ferraro cautions that the EPRI study will only give early indications of potential savings because PCSs for utility applications still have a long way to go. But if this PCS strategy works, fossil fuel plants can be saving electricity while developers learn more about PCSs for new technologies. Both today's and tomorrow's power plants come out ahead. □

and capacity credits for wind and photovoltaics; these procedures are based on generation planning techniques readily available to utilities. Ways of estimating transmission and distribution credits have also been established.

The methodologies have been applied on a number of utility systems. In most cases, wind turbines were found to be unlikely candidates for capacity credits; the source is too intermittent for utilities to rely on for firm load-carrying capability. Nevertheless, wind has the potential to displace significant amounts of fuel for a utility, which may make it particularly valuable in areas where wind would replace oil-fired generation. The potential effects of dispersed wind turbines on transmission and distribution (such as a reduction in power losses) were found to be negligible. Use of the photovoltaic methodologies turned up much the same result: capacity credits were unlikely; fuel credits were more likely, but very utility-dependent; transmission and distribution credits were insignificant.

The EPRI methodologies for wind and photovoltaics have been available to utilities for about three years now for use in determining whether photovoltaics or wind might be feasible on a particular network. Utilities can use these methods to calculate a statistical capacity credit from utility system reliability studies. Nevertheless, extensive operating experience with these new sources will be required before the calculated credits can be verified.

Besides altering some of their forward planning, utilities may also have to alter day-to-day systems operation and control if they are to use these new technologies. Current operation and control systems are designed for the generation and transmission of large blocks of power from central power plants; control of subtransmission and distribution is largely decentralized and automatic. Fuel cells, batteries, and other new technologies will be more likely to generate smaller amounts of power from local plants dispersed throughout utility distribution networks, and utilities will have to rethink systems operation and control accordingly. The issues of operation and control become even more complicated in situations where dispersed generation is privately owned, and when surplus power is sold to utilities by the private owners.

Broader concerns

Total energy delivery systems for new technologies will not be complete without attention to institutional concerns. These go beyond the jurisdiction of the utilities and may prove to be the most difficult aspect of total energy delivery simply because they involve so many groups and individuals.

One important institutional issue that must be resolved before new technologies can appear in electricity networks is safety and liability. Although utilities are now generally responsible for accidents and property damage that occur on their systems, they are also in total control of those systems: when a storm knocks down a distribution line, the utility can shut off power to the line, and repairmen and bystanders can be reasonably safe as they go about their business. But when dispersed generation comes along, possibly owned by private individuals or organizations, responsibilities become muddled. A private individual may use utility lines under applicable PURPA regulations, but this generation is not under utility control. If a storm downs a distribution line and the local utility shuts off power to the area, the privately owned generation unit may keep on producing power, potentially harming people or equipment. The responsibilities of the utility and the private generator must be more clearly designated; contracts for liability must be drawn up, and insurance requirements must be established to accommodate the new situation.

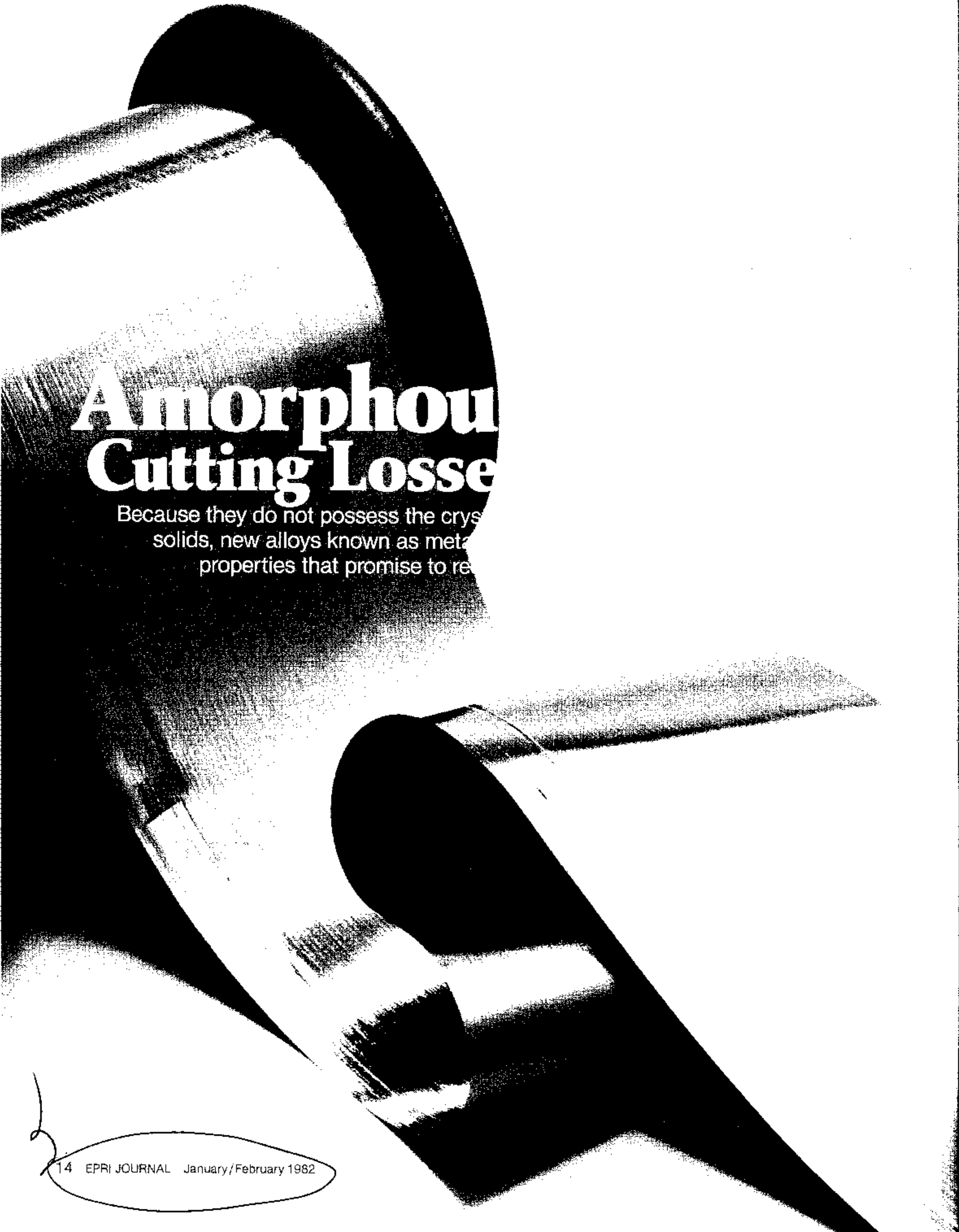
Problems could also appear in the area of metering and billing. Utilities now do all electricity metering and billing because they provide all the power their customers use. When private individuals begin to produce their own power and sell the surplus to utilities, an entirely new system of metering and billing will have to be established. Responsibilities and costs for such a system have yet to be specified.

Another difficult institutional issue concerns power standards. Measures of power quality have not been sharply defined, but before individuals begin to sell power to utilities and other parties, standards must be set and enforced. This will ensure that a specific level of power quality is maintained and that utility and customer equipment is not damaged by lower-quality power.

Still other institutional questions stand unanswered. Land use is a potentially troublesome question, because some new technologies, such as wind and photovoltaics, are site-dependent for success, and suitable sites may be coveted by other interest groups. Subtle environmental effects are also a question mark, for while coal, oil, gas, and nuclear have been around long enough to build up data on their environmental effects, the possible impacts of new technologies may take years to be identified and then corrected.

New technologies may seem to be complete systems that will stand by themselves, generating electricity imperturbably regardless of the rest of the utility system. "But these systems are really only subsystems, pieces of a larger system," concludes Ferraro. With power conditioners, with new generation planning techniques, with revised operation and control systems, and with answers to institutional issues, the electricity from new energy technologies can be delivered successfully to utility customers. ■

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



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Because they do not possess the crys
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properties that promise to re

High above the floor of a small industrial plant in Morristown, New Jersey, a heavy ladle pours a stream of glowing molten metal into the hopper of a miniature steel mill. Soon, from one end of the mill, a slightly iridescent strip of metal only 1.5 thousandths of an inch thick begins to spew forth. This strip represents an important new technology that may eventually save electric utilities hundreds of millions of dollars annually. When wound or stacked into transformer cores, the new material can reduce the energy losses that take place in these cores by more than 60%.

The strip is made of a fundamentally new kind of material—an amorphous metal—in which the atoms and molecules are arranged more or less randomly. Usually, molten metals crystallize when they cool; that is, their atoms arrange themselves in an orderly pattern with even spacing between them. In contrast, amorphous metals have an internal structure more like that of glass, with orderly arrangement extending a distance of only a few atoms in any direction. Long thought to be an impossibility, these metallic glasses, as they are sometimes called, can be created by cooling a molten alloy so fast that its atoms do not have time to arrange themselves into crystalline form.

This lack of internal order has a profound effect on the metal's physical properties. Some amorphous alloys are among the strongest metals known. Others are unusually corrosion-resistant. But by far their most important property from the point of view of transformer manufacture is their lack of a preferred direction for magnetization. Most metals can be thought of as containing many tiny permanent magnets, which can be lined up most easily along one axis of the crystalline array. In a transformer core, considerable energy must be expended in flipping these magnetic domains back and forth as current changes direction in the wires wound around the core. Because the magnetic domains of amorphous alloys are not constrained by crystalline boundaries or crystallographic directions, they respond easily to the force of an external magnetic field.

As a result, amorphous alloys are said to be magnetically soft—a property ideal for transformer cores. When the current changes in one set of windings, the magnetic flux set up is transferred throughout the core with very little loss of energy. The transformer then uses this flux to induce a current flow in another set of windings, with either a higher or a lower voltage, depending on the relative number of turns in each set. In the United States, standard alternating current goes through 60 cycles each second, which means that the direction of the magnetic flux in a transformer core changes 120 times per second. Sharply reducing the energy lost (as heat) with each change could save considerable amounts of money, provided that the cost of making transformers from amorphous metals is not too much greater than the cost of ordinary transformers.

It is this critical question of ultimate relative cost that is now the focus of an $8 million, five-year research project sponsored by EPRI. As part of this effort, Allied Corp. is producing tons of amorphous metal at its transformer ribbon plant in Morristown. Westinghouse Electric Corp. is then fabricating transformer cores from the material and conducting cost analyses. The project is now about three-fourths completed, with favorable test results reported by both contractors.

Ribbon and core manufacture

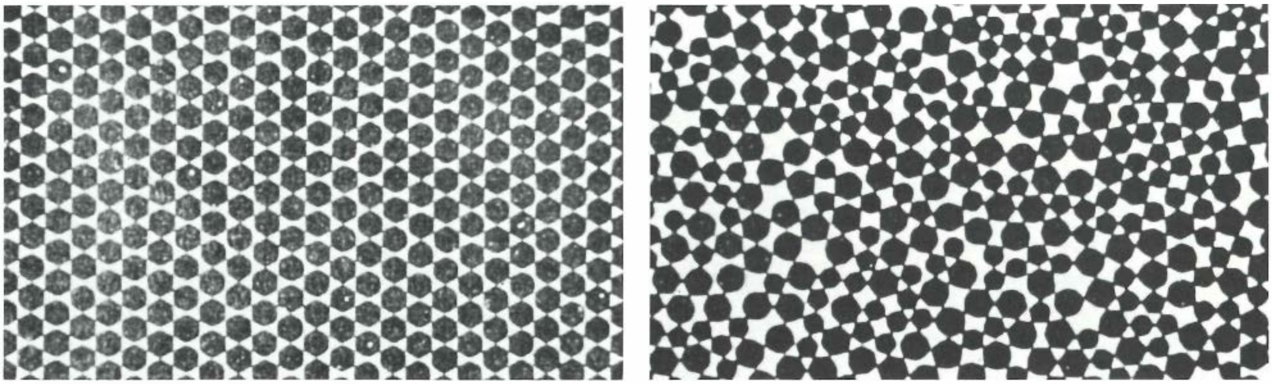
At the Morristown facility, Allied is creating 2-in-wide (5-cm) and 6.7-in-wide (17-cm) ribbons of its patented Metglas brand of amorphous alloy (Metglas is an Allied registered trademark). Composed primarily of iron, boron, and silicon, Metglas amorphous alloy ribbons are formed by cooling the molten metal at the rate of about one million degrees Celsius per second. Conceptually, the process is simple: it involves shooting a thin stream of liquid metal through a nozzle onto the cool surface of a moving substrate, such as a rotating wheel. In practice, however, it is very complicated and already involves more than 250 patents and applications worldwide. Success depends greatly on the specific composition of the alloy, the viscosity of the molten material, the exact rate of cooling, and the geometry of the strip. So far, the Morristown plant has made two-hour casts of ribbon, and the system can be readily extended to essentially continuous operation in a commercial plant. Such a plant would have considerably lower capital costs than a plant for making the silicon-iron alloy typically used in transformer cores. The reason is that although the amorphous alloy fabrication technology is complicated, it involves far fewer metal-working steps.

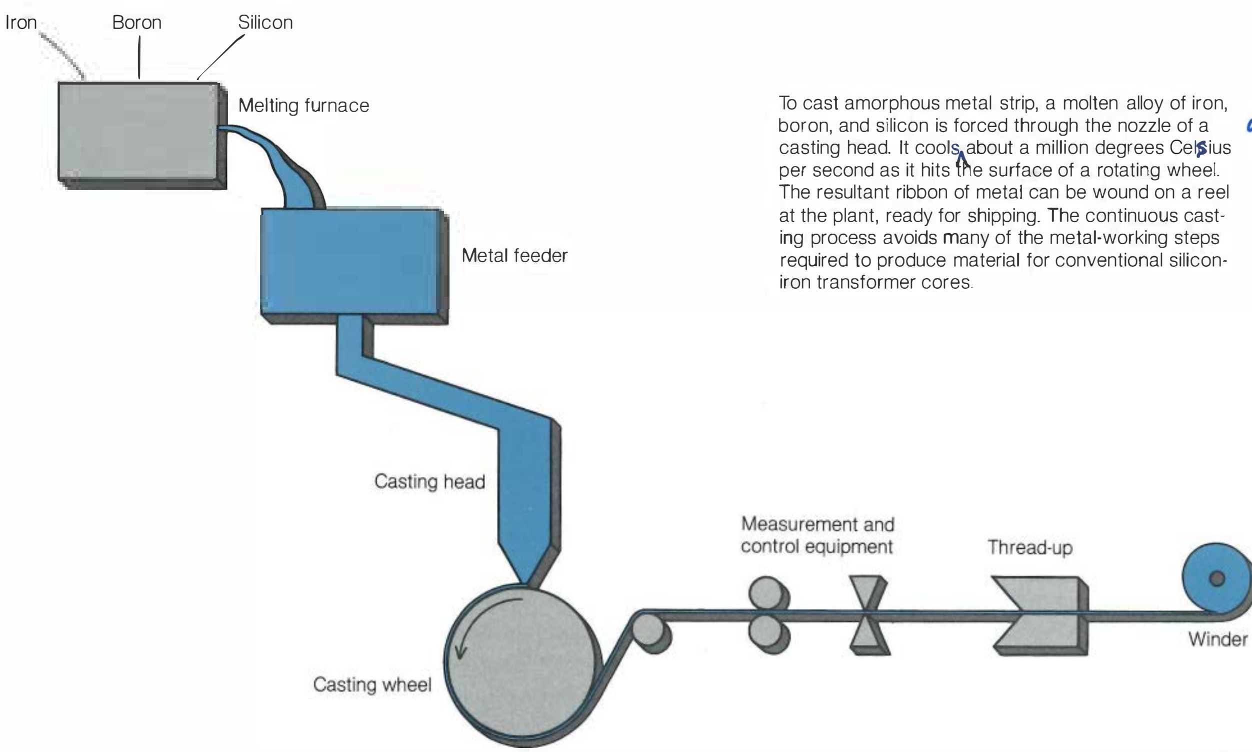
As the ribbon emerges it can be wound on a reel, ready for shipping. When samples arrive at the Westinghouse Research and Development Center in Pittsburgh, Pennsylvania, they are used to fabricate two kinds of transformer cores, which are then subjected to analyses. For one type, the ribbon is rewound and formed into a roughly rectangular shape to make the relatively small cores used in distribution transformers. These wound-core transformers are a familiar sight atop utility poles, where they lower voltage to the 120/240 V appropriate for home use. For power transformers above 500 kVA and up to 765 kV, stacked (or plate) core construction is used. The legs and yokes of the cores of these units are made up of laminations of steel that are formed by slitting, shearing, and die-punching the original sheet of metal.

For both kinds of cores, considerable problems can arise during the fabrication process because of the extraordinary properties of amorphous metals. In order for an amorphous metal to exhibit excellent magnetic properties, the metal must be annealed at some point during transformer manufacture. In a conventional wound core, the electrical windings are typically assembled on a preformed, jointed, annealed core by partially pulling the core apart at its joints, installing the coils, and reassembling the jointed core. Amorphous metal is too brittle to be handled in this way after it has been annealed. The solution to the construction of an amorphous metal core is either to find a way to wind the annealed, unjointed core material around a completed set of coils or to wind the coils around an annealed, completed core.

In stacked cores, amorphous alloys may simply be introduced as replacement materials for the silicon-iron laminations now in common use; in this case new core fabrication processes would not be required. However, severe handling problems for the ribbon itself would still remain. This material is so hard that blades used to shear the laminations would not last long. The ribbon's thinness is another problem. To facilitate handling, it may be necessary to modify the casting process to produce thicker ribbons, and/or to find ways of bonding the ribbons into thicker laminations. Efforts

Like most metals, the molten silicon-iron normally used to fabricate transformer cores crystallizes as it cools to take on a regularly patterned internal structure (left). Amorphous metals, on the other hand, are cooled so quickly that their atoms do not have time to form a crystalline pattern (right), which gives the metal unusual strength and magnetic properties.





To cast amorphous metal strip, a molten alloy of iron, boron, and silicon is forced through the nozzle of a casting head. It cools about a million degrees Celsius per second as it hits the surface of a rotating wheel. The resultant ribbon of metal can be wound on a reel at the plant, ready for shipping. The continuous casting process avoids many of the metal-working steps required to produce material for conventional silicon-iron transformer cores.

are also under way to produce wider ribbons, but this will require major advances in the technology of refractory materials, heat transfer techniques, and materials handling. For both wound and stacked cores, the development of new, high-speed robotized technology may prove critical to solving fabrication problems in a cost-effective manner.

A few experimental transformer cores have been constructed from the amorphous alloy ribbon, and already the advantages of the new material in reducing energy losses have become evident. For example, the presence of a changing magnetic field induces small electric currents in the core itself; these energy-robbing eddy currents are minimized in the amorphous alloy because of its thinness and its inherently high resistance to the flow of electricity. Another energy loss normally occurs as the external magnetic field reverses the orientation of the magnetic domains inside the core material; this hysteresis loss is also smaller in amorphous alloys than in silicon-iron. There is a third area—energy loss due to motion of the walls of the magnetic domains—in which amorphous materials perform more poorly than silicon-iron. However, the importance of this loss factor is much smaller than that of the two areas in which the new alloys excel. Overall, amorphous alloys may cut core losses experienced with silicon-iron by 60% or more.

Cost factors

How well these inherent advantages can be translated into practical savings will depend on how they affect the balance of a transformer's initial cost to the buyer and its operating cost. Generally, the cost of building a transformer is lower if strong magnetic fluxes are to be used in the core, but the cost of energy losses rises with a higher induced flux density. The goal is to find the density level that will minimize the total cost when both initial and operating costs are considered.

The usual method for evaluating energy losses in a core is to calculate the present value of future costs under no-load conditions over the lifetime of the transformer. Ten years ago, when energy was still inexpensive, the value of these losses was assumed to be about $1000/kW. At this rate, to minimize total costs silicon-iron cores were designed to have a magnetic flux density of about 17 kG (1.7 T). Because amorphous materials cannot accept that much magnetic induction, they would have been placed at a distinct disadvantage.

Now, however, the cost of making up for energy losses in a core has risen substantially—to about $7000/kW—which would make the optimal flux density for silicon-iron cores only 12 kG (1.2 T). But because the losses are smaller with amorphous metals, the optimal level for these cores would be 14 kG (1.4 T), and this higher flux density would significantly reduce the initial transformer cost. Therefore, the total cost of building and operating transformers now appears to be considerably lower if amorphous alloys are used—provided the raw material itself is not too expensive.

Commercial production of amorphous metal strip for utility transformers is expected to begin by 1985. According to Reed Belden, the Allied vice president who heads the amorphous metals program, the initial commercial pricing for Metglas amorphous metal strip will be in the range of $1.50–$2.00/lb. Although this represents a premium over the current price of silicon iron, the dollar value of core loss savings from using amorphous metal should provide a sufficient margin to benefit utility companies and provide an incentive for the transformer manufacturers. Obviously those utilities with the highest cost of power will be the first to adopt and benefit from this new technology. As the price of energy increases and the price of amorphous metal decreases with higher volume, additional utilities will be able to benefit from amorphous steel transformers.

Part of the aim of the present EPRI project is to determine whether ribbon costs can, indeed, be brought into the acceptable range. The outcome will depend on several factors. One is that as Metglas amorphous alloys contain substantial amounts of boron, which is much more expensive than iron, the final cost of the alloy will depend largely on whether ways can be found to obtain this element more cheaply than in the past. Transformer cores would represent a major new market for boron, so considerable effort is being made to develop alternative means of producing it.

Another factor is that the amount of metal actually needed in a core depends in part on the amount of empty space that occurs as the result of the surface finish of the material to be wound or stacked. (The surface finish of the amorphous alloy ribbon is slightly rougher than what would be considered a mirror finish, and when layers of the ribbon are placed on top of one another, this roughness causes some empty space to remain between the layers.) The fraction of total core volume that is filled with metal is called the space factor. Conventional cores typically have space factors of 95% or better, but for cores of amorphous materials the figure is only about 80–90%. Further work is being conducted on strip casting to determine if better space factors can be achieved.

For the moment, then, amorphous alloys are generating considerable excitement because of their promise for reducing transformer core energy losses. EPRI Project Manager Edward Norton estimates that the potential energy savings could amount to $200 million a year. Moreover, through further research, it may also eventually be possible to make transformers with amorphous alloy cores that are less expensive than transformers with silicon-iron cores. With three-fourths of EPRI's research program completed, Norton is guardedly optimistic: "It's an exciting new technology that offers great potential rewards, but we have a lot of work left to do." ■

This article was writen by John Douglas, science writer. Technical background information was provided by Edward Norton, Electrical Systems Division.

Trade-offs in NO_X Control

Research suggests that advanced furnace and burner designs a few years from now could permit NO_X emissions significantly lower than today's standards at costs only incrementally higher. A central question is whether further reductions through flue gas treatment can be economically justified.

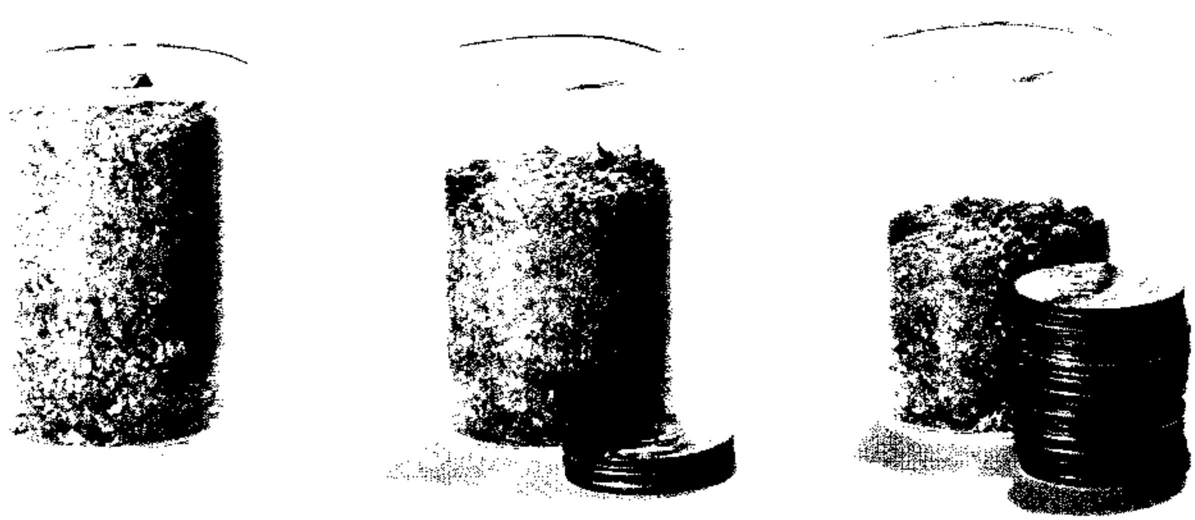
Trace the history of emission regulation on coal-fired power plants and you'll find it dominated by limitations on particulate matter and sulfur dioxide (SO_2). Trace the path of the exhaust ductwork in a modern plant and you'll find it dominated by the housings of fly ash precipitators (or fabric filters) and SO_2 scrubbers.

Nitrogen oxides (NO_x) also result from coal combustion. NO_x emissions are regulated, but this is not generally known and the control equipment is not apparent.

Subtler effects, easier control

Uncontrolled particulate emissions can be seen, and the odor of SO_2 can sometimes be discerned. These emissions were long ago acknowledged to be health hazards although just how hazardous remains a point of contention. The major sources of these pollutants—smelters and power plants—are large and easily identified, making emission reduction a manageable matter. The control equipment itself is bulky and obvious because of the large internal surface contact area required to ensure effective pollutant removal for the entire volume of exhaust gas.

NO_x emissions, however, may not be visible at the stack. The troublesome combustion product is nitric oxide, (NO) which easily oxidizes to nitrogen dioxide,



Uncontrolled combustion — 0% reduction

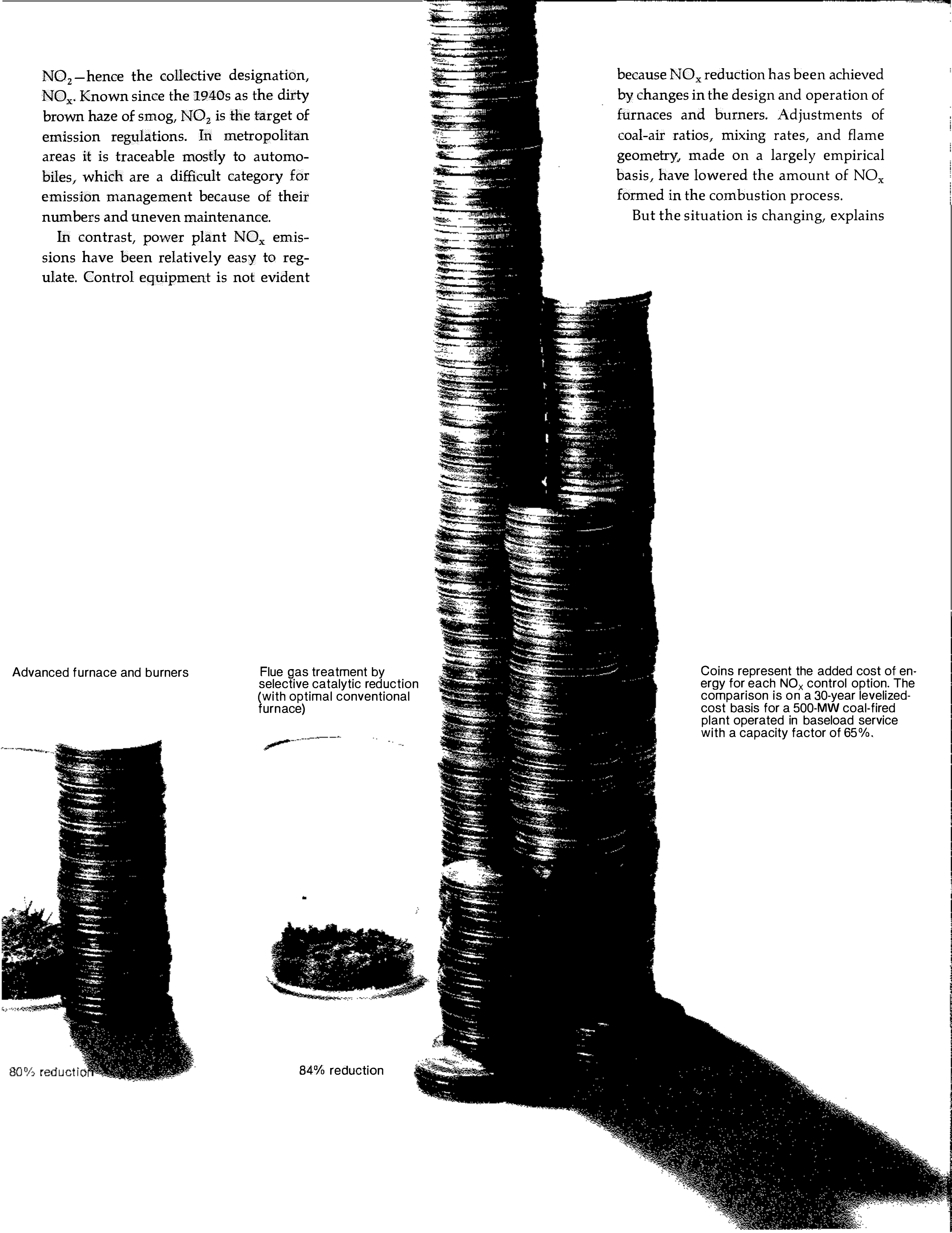
Conventional furnace with optimal operation — 20% reduction

Conventional furnace with low-NO_X burners — 50% reduction

NO_2—hence the collective designation, NO_x. Known since the 1940s as the dirty brown haze of smog, NO_2 is the target of emission regulations. In metropolitan areas it is traceable mostly to automobiles, which are a difficult category for emission management because of their numbers and uneven maintenance.

In contrast, power plant NO_x emissions have been relatively easy to regulate. Control equipment is not evident because NO_x reduction has been achieved by changes in the design and operation of furnaces and burners. Adjustments of coal-air ratios, mixing rates, and flame geometry, made on a largely empirical basis, have lowered the amount of NO_x formed in the combustion process.

But the situation is changing, explains



Coins represent the added cost of energy for each NO_x control option. The comparison is on a 30-year levelized-cost basis for a 500-MW coal-fired plant operated in baseload service with a capacity factor of 65%.

Michael McElroy, a project manager for NO_x control in EPRI's Environmental Control Systems Department. "The industry is using more coal, and not just in new plants. Where practical, utilities are converting back to coal because the cost of oil is so high and its supply is uncertain. At the same time, there's a lot of new thinking about NO_x as an air pollutant, especially in connection with acid rain. There are pressures to reduce NO_x at existing plants, as well as at new ones."

McElroy also acknowledges that the traditional avenue of NO_x control at the point of combustion is becoming a narrow path of very exacting technology, while the emerging postcombustion processes for NO_x removal are already considered to be as expensive and operationally complex as the scrubbers for SO_2. All these circumstances are incentives for attention by the electric utility industry.

NO_x down, cost up

Before emission regulation began, combustion efficiency and heat transfer performance governed power plant furnace design and operation—with due regard, of course, for temperature limits needed to avoid molten slag formation. Measurements on older plants show NO_x emission rates as high as 1.5 lb for every million Btu (1.5 lb/10^6 Btu) of heat released from the fuel. The first federal NO_x limitation was 0.7 lb/10^6 Btu, set by the New Source Performance Standards (NSPS) of 1971. The revised NSPS of 1979 acknowledged the influence of coal composition by setting two NO_x limits: 0.6 lb/10^6 Btu for bituminous coal and 0.5 lb/10^6 Btu for subbituminous coal.

R&D in this country and abroad, especially in Japan, suggests that furnace and burner designs a few years from now could permit plant operation with NO_x emissions significantly lower than today's standards.

An entirely different NO_x reduction concept is that of removing it by chemical treatment of the flue gas stream. There are at least 50 variants of this approach, several of them generically termed selective catalytic reduction (SCR) and featuring the use of ammonia. Pioneered in Japan, SCR is further developed than other postcombustion processes. SCR achieves 60–80% reduction of flue gas NO_x, comparable with what may soon be possible by combustion modifications.

For NO_x emissions significantly below today's NSPS, refinements in furnace and burner designs will probably add only incrementally to the cost of a new power plant. The alternative, a flue gas treatment system for about the same degree of control, could add $75–$100/kW. If low-NO_x combustion system designs become available, and especially if they can be retrofitted to existing plants, it is unlikely that the much greater cost of SCR or other flue gas treatment systems could be justified. Still, which technology will be used, when, and under what circumstances are not clear.

Two EPRI divisions are at work accordingly. In the Energy Analysis and Environment Division, researchers of the Environmental Assessment Department are investigating the origins and transport of NO_x in the atmosphere, the mechanisms of its transformation and action as a pollutant, and the costs of public health and other ecological consequences. In the Coal Combustion Systems Division, McElroy and other R&D managers of the Environmental Control Systems Department define and test the processes that occur in the furnace or that can be added in the flue gas stream to control NO_x. It is important that each control technology be correctly ranked in performance, reliability, and cost.

NO_x formation

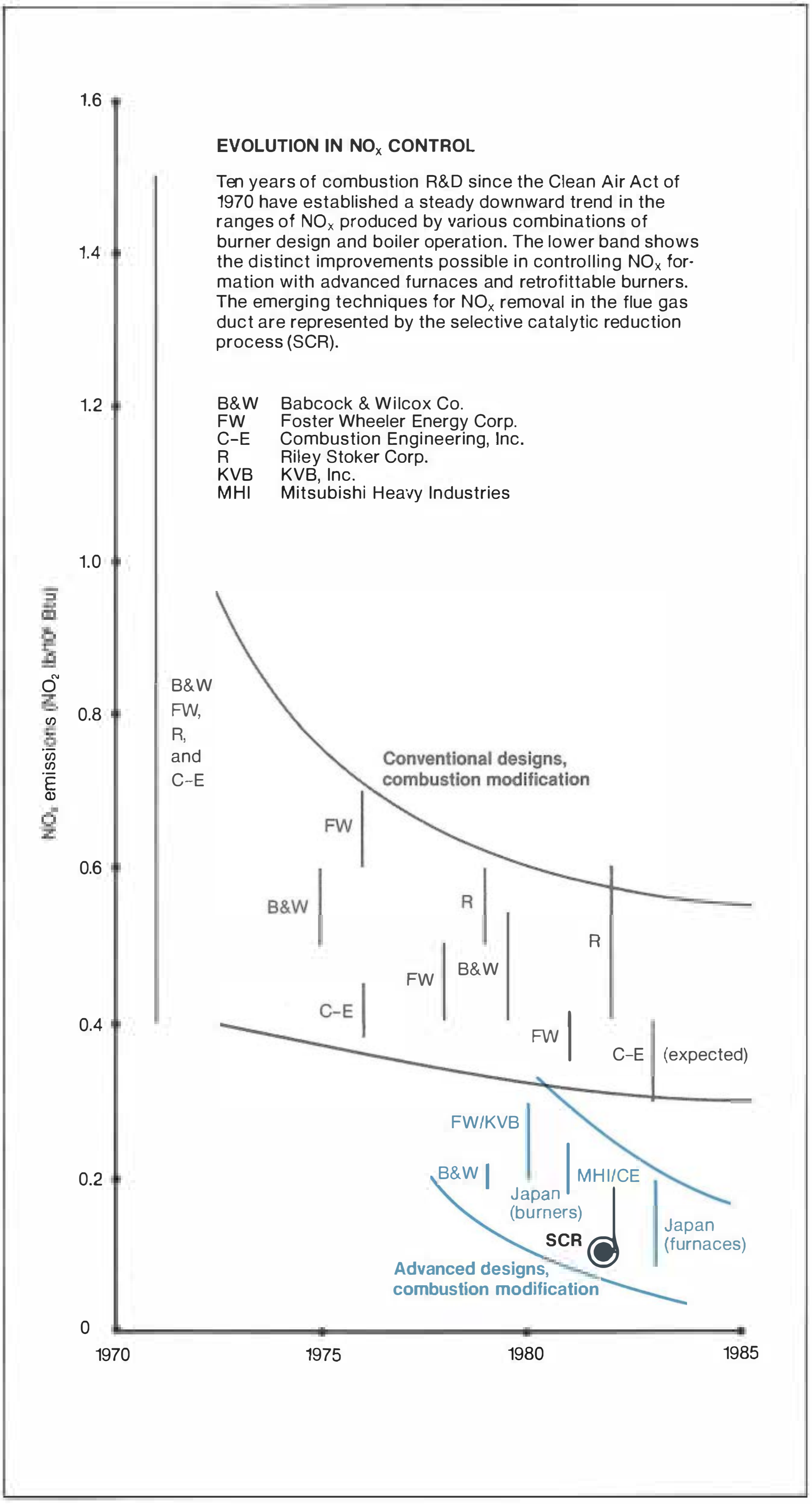
The opportunity to control the emission of a pollutant by controlling its formation sets NO_x control technology apart from that of SO_2 control. Sulfur is a constituent of coal, from which it oxidizes straightforwardly in combustion. The immediate and unavoidable product SO_2 is fairly stable in the normal flue gas environment.

But coal combustion involves two sources of nitrogen, the coal itself and the air introduced to supply oxygen for the combustion process. Depending on the combustion variables, the nitrogen tends to follow different reaction sequences in which either NO (highly reactive) or N_2 (inert) dominates. Those process variables and their aftermath can be controlled by both the designer and the operator of a power plant boiler. To reduce the ultimate NO_2 content of the ambient air, it is necessary to control the formation of NO at the combustion source.

NO_x derived from nitrogen in the combustion air is called thermal NO_x. It is about 20–40% of all the NO_x from an uncontrolled boiler. Its formation is mostly a function of combustion temperature, and the easiest way to lower it is by delayed mixing of fuel and air. Burners and their dampers are the first things to adjust: the passages that meter and combine pulverized coal and air in specified ratios and patterns. The configuration of burners can also be altered: their number and spacing and the provision of supplemental air ports among them. Some of these measures can be retrofitted; others are possible only in new designs. For example, because delayed mixing results in a longer time for complete burnout of carbon, optimal design may call for a boiler with a larger combustion zone, whose greater surface area and heat-transfer capability aid in holding the temperature down.

Delayed mixing has its limits, however. "Taken too far, it results in unburned hydrocarbons and reduced combustion efficiency," says McElroy. "In extreme cases it may lead to a chemically reducing atmosphere that can corrode the furnace walls." Even so, thermal NO_x reduction has been a relatively easy avenue, involving operational and design changes on conventional equipment. These measures are largely responsible for utilities' compliance with today's emission regulations.

NO_x evolved from nitrogen in the coal is called fuel NO_x. It is about 60–80%



EVOLUTION IN NO_x CONTROL

Ten years of combustion R&D since the Clean Air Act of 1970 have established a steady downward trend in the ranges of NO_x produced by various combinations of burner design and boiler operation. The lower band shows the distinct improvements possible in controlling NO_x formation with advanced furnaces and retrofittable burners. The emerging techniques for NO_x removal in the flue gas duct are represented by the selective catalytic reduction process (SCR).

of the total, depending on coal composition and flame-zone chemistry. The remedy is subtly different from delayed fuel-air mixing; it involves the fuel-air ratio from start to finish. Control of fuel NO_x calls for an initial combustion zone that is fuel-rich, followed by a separate zone where more air gradually becomes available for complete burnout.

This staged process favors the formation of inert N_2 instead of reactive NO. Because fuel NO_x is the larger contributor to NO_x emissions (and because the easier solution of thermal NO_x control is already in use), fuel NO_x gets most of the attention in today's R&D. It is the target of advanced low-NO_x combustion systems with their revolutionary burner and furnace designs.

Furnace modification

The distinction between burner and furnace is important. Burners govern the ratio and injection pattern of coal and air entering the furnace, but the size and shape of that chamber influence the overall thermal, kinetic, and other combustion phenomena that follow. New furnace geometry is considered only in the design of new units. Two EPRI-sponsored projects are the only known R&D specifically addressing furnace designs that will produce less NO_x. The research illustrates the roles of theoretical and empirical work in this field.

A venturi passage separates the two combustion stages of the hourglass-shaped primary combustion furnace (PCF) developed by Babcock & Wilcox Co. The design has a solid theoretical basis in studies of NO_x formation; at pilot scale the PCF has held NO_x emissions to 0.2 lb/10^6 Btu. B&W has predicted similar emissions for full-size utility boilers, and the cost is estimated to be about $6/kW more than that of today's conventional utility furnaces.

In complementary work, two EPRI contractors have explored the coincidentally low NO_x emissions of a 64-year-old furnace design. KVB, Inc., has documented the performance of arch-fired units operated by Wisconsin Electric Power Co. Eastern and western coals have been fired in units ranging from 80 to 275 MW, under different loads and with varied air-flow distributions in the furnaces. The KVB work substantiates both the NO_x inhibition and the excellent availability of the Wisconsin utility's arch-fired units.

Foster Wheeler Energy Corp. still builds arch-fired furnaces for industrial users who burn anthracite and other slow-burning fuels. But the design tends to cost more than typical configurations for other coals. Foster Wheeler is therefore investigating the economic feasibility of using the arch-fired design in utility plants at the scale of modern plants. Assured operability and accurate cost projections are the research objectives.

Staging is the shared feature of all low-NO_x furnace designs. But the chemistry is often different, as, for example, with an in-furnace process developed in Japan. Special burners placed high in the furnace are used to reburn NO_x-laden gases rising from the initial flame zone, thus reducing NO_x to N_2. The scheme amounts to flue gas treatment with a flame; it is likely to receive a lot of R&D attention. Performance details are not yet widely known, but reburning has been applied experimentally in the reconstruction of an oil-fired utility boiler in Japan.

There are generic problems in combustion modifications, apart from adapting a process designed for one fuel to another or transferring a process from one country to another. NO_x formation is governed by geometric, kinematic, thermal, and chemical phenomena that do not vary in the same manner when furnace design scale is enlarged or reduced. R&D results (mostly recorded at laboratory scale) are not a reliable index of real-world performance. As a result, McElroy says, "NO_x controls have evolved in an incremental fashion—a series of

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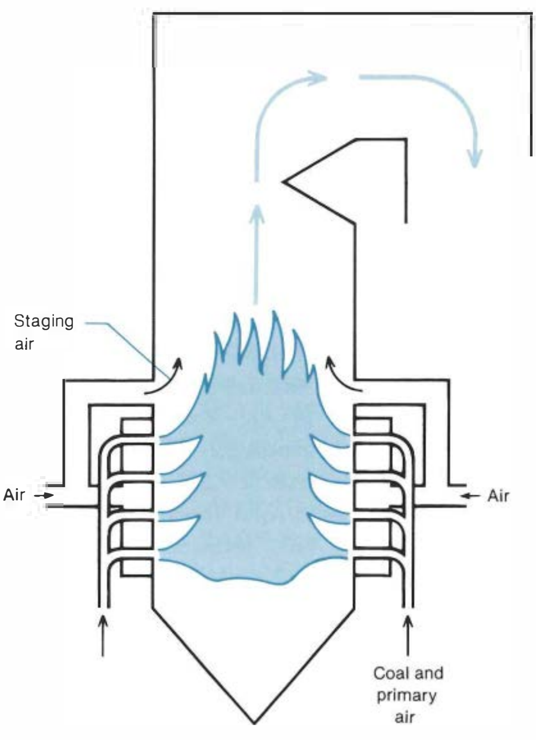
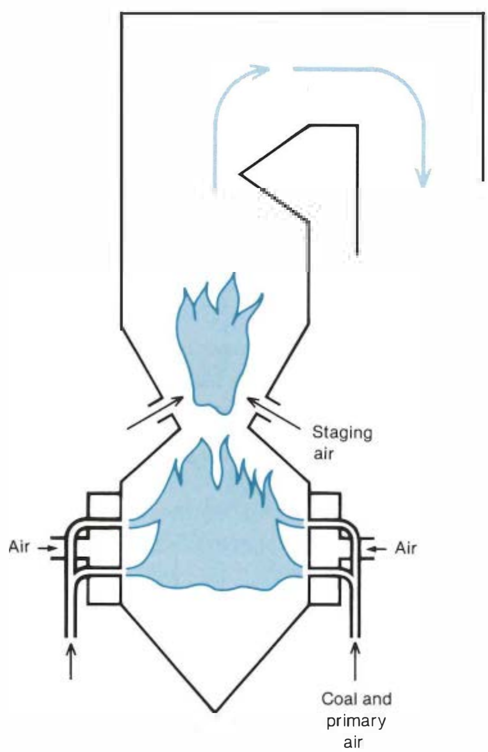
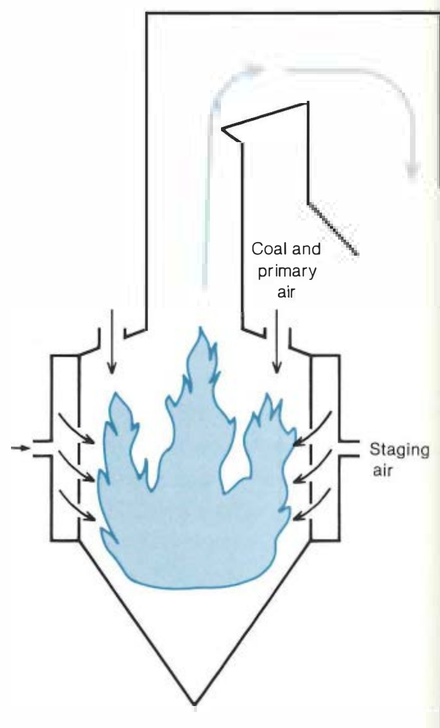


Conventional furnace with low-NO_x burners and overfire staging air.



B&W's primary combustion furnace with second-stage combustion beyond a venturi throat.



FW's arch-fired furnace with downward-firing burners and sequenced staging air.

technology advances involving field trials to demonstrate operability before being commercially offered by manufacturers.

"We hope basic research can help us do more orderly modeling of combustion designs. But efforts so far have been unsuccessful, and there's still no universal model of NO_x formation and control for accurately predicting the NO_x performance of new boiler designs."

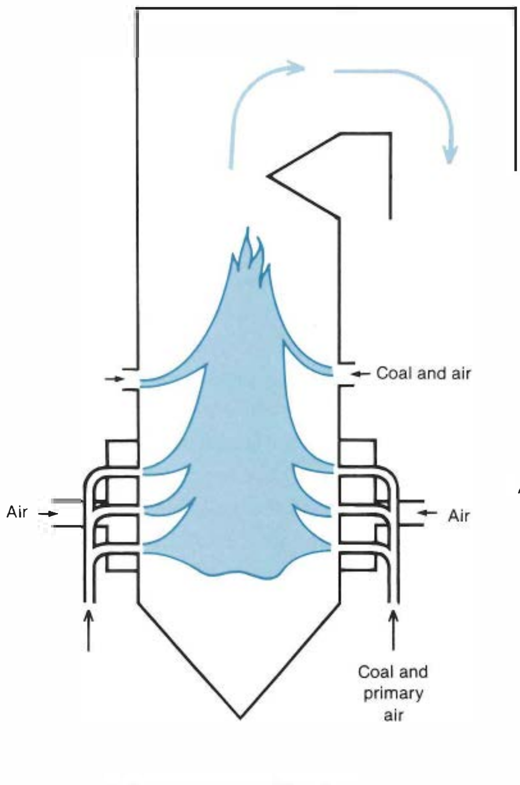
Retrofittable burners

Utilities may need to retrofit new technology to existing sources. The cost and availability of retrofittable NO_x controls are therefore becoming important issues in the operation and expansion of coal-fired power plants.

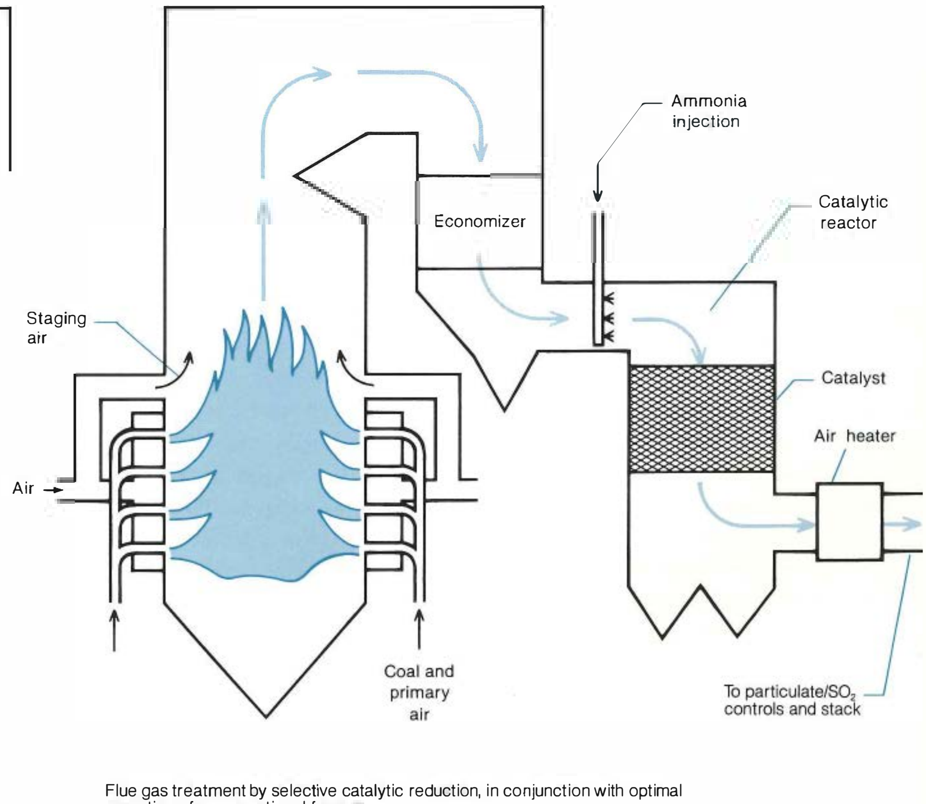
Retrofit measures are appealing because there are a variety available to meet different cost and performance objectives. The first steps are plant operational changes, such as control adjustments on burners and alterations of fuel-air balance. Burner modification is the next step in cost and complexity, but it can be expected to reduce NO_x emissions more sharply. Within limits, the internal parts of burners can be redesigned to change coal and air injection rates, paths, and patterns.

Retrofit becomes modification when new burners cannot simply be plugged in. Enlarging or repositioning burner locations almost certainly requires changes in pressure parts: the water and steam tubes of the furnace wall. Such field work, largely cutting and welding, is expensive.

Two projects best represent EPRI's work toward retrofittable low-NO_x systems. One of them, just now being completed, is the combustion testing of a burner developed by Mitsubishi Heavy Industries (MHI) in Japan. The test program has also involved Japan's Electric Power Development Co. and Combustion Engineering, Inc., licensee for the MHI burner in the United States.



Japan's reburning furnace, with upper burners for reducing the NO_x formed below.



Flue gas treatment by selective catalytic reduction, in conjunction with optimal operation of a conventional furnace.

The burner was designed for use in new tangentially fired boilers, but it is retrofittable. (Burners are in the corners of such a furnace, aimed so that the coal-air streams are tangential to a cylindrical flame zone.) Tested with a variety of U.S. coals, the MHI burner showed a remarkable capability (at pilot scale) for controlling combustion parameters. NO_x emissions as low as 0.2 lb/10^6 Btu were recorded.

Tangentially fired boilers account for about half the total among U.S. utilities. The others are wall-fired, usually with burners on two walls firing in direct opposition toward each other. Retrofittable low-NO_x solutions for wall-fired units will also be addressed by EPRI-sponsored research over the next three years. Two or more contracts are to be awarded to U.S. manufacturers to ensure that a range of systems is available to utilities. Complementary studies of somewhat longer duration will assess the boiler design and operating characteristics that favor or discourage retrofit and the degrees of NO_x reduction that might be sought by various approaches involving burners and controls.

Other R&D in this country, as well as in Europe, also addresses retrofittable low-NO_x burners. A distributed mixing burner, developed under EPA sponsorship by Energy and Environmental Research Corp., is intended for wall-fired furnaces, although its size requires a larger opening and consequent pressure-part changes. A concentric arrangement of coal and air openings encourages an eddying flame zone of progressive, staged combustion. At laboratory scale the burner reportedly produced as little as 0.2 lb/10^6 Btu, but its performance and prospects at commercial scale are yet to be demonstrated.

Another system for tangential firing, the rich fireball, was developed by Combustion Engineering and by Acurex Corp. — the latter under EPA sponsorship. It is now being demonstrated in a 450-MW Utah Power & Light Co. unit. This relatively inexpensive scheme features a fuel-

SERENDIPITOUS NO_x CONTROL

Engineers of what is now Wisconsin Electric Power Co. (Wepco) unwittingly pioneered low-NO_x coal combustion when they introduced pulverized coal firing more than 60 years ago. At that time, crushed coal was the familiar fuel, fed into furnaces on the moving grates of mechanical stokers, with combustion air forced through the coal bed from below.

Finely pulverized coal offered better efficiency because its far greater surface area permitted faster and more complete contact with combustion air. It could be blown into the furnace in a stream of air. Geometric control of the flame zone (by the orientation of multiple burners) would later become possible, as would control of additional air to intensify and complete the combustion process.

Wepco's predecessor company hit upon what we call arch firing in the course of converting stoker-fired equipment in 1918. Downward-firing burners were fitted in the flatly sloping furnace roof (the arch) as a matter of convenience. Air was added through ports in the furnace wall to direct the flame away from its refractory surface, which otherwise would become so hot as to cause slagging—the melting and erosive action of the fly ash. Because a downward-directed flame must eventually turn and go up, a U-shaped pattern resulted, with heat release along its full extent.

The configuration worked successfully. It was the beginning of pulverized coal firing by utilities and was adopted during the 1920s by, among others, Detroit Edison Co., Cleveland Electric Illuminating Co., Union Electric Co., and Consolidated Edison Co. of New York. High-turbulence burners and other features eventually superseded the arch-fired furnace in utility industry practice, but Wepco continued to use its familiar design for new plants until 1961.

How did we learn of the inherently low NO_x emissions from this furnace? It was serendipity—the finding of something valuable without seeking it. While doing combustion tests at Wepco plants a few years ago, KVB, Inc., recorded surprisingly and consistently low NO_x measurements. Subsequent systematic testing for EPRI resulted.

Why does the arch-fired furnace perform as it does? Partly because the primary air at the burner is little more than a transport vehicle for the coal and partly because the sequential air addition—up to 80%—through a vertical series of ports in the furnace wall has the effect of drawing out an initially air-starved process. The chance combination constitutes modestly delayed and staged combustion, both of which inhibit NO_x formation. □

rich (low-NO_x) flame at relatively low temperature, achieved by diverting some of the normal air flow along the furnace walls. This air rises and rejoins the combustion zone for complete burnout higher up.

Overall, combustion modification (for new units or by retrofit) is attractive because NO_x reduction becomes part of boiler design and operation and because the equipment cost is relatively low; burners and boilers must be designed and built anyway. Removal of NO_x from the flue gas stream is completely different.

Flue gas treatment

Postcombustion removal of NO_x from flue gas is of interest today, but regulators and utilities view its accomplishment quite differently. The SCR process is well enough developed that local air quality regulators in a few instances have used it as the basis for startlingly low NO_x emission standards. An example is the limit of 0.09 lb/10^6 Btu that was established in California for coal-fired plants. SCR processes would add \$75–\$100/kW to a utility's new power unit costs, however, and as much as \$25/kW-yr to operation. Utilities therefore observe that emission standards requiring this technology for attainment would add appreciably to the cost of coal-fired electricity.

Cost is the common thread running throughout EPRI's investigations of flue gas NO_x removal. Equipment capital cost is one thing. Operating cost is another. The effect on other plant systems and their reliability must also be considered, as well as the cost of net energy penalty on plant output.

Two areas of EPRI research have addressed these matters. One was a series of studies that encompassed some 50 postcombustion NO_x removal processes. The consensus was that SCR has more potential than other flue gas treatment schemes because it is a dry process, produces no solid waste, is generally retrofittable, and has been extensively developed in Japan. Some other processes offer theoretically better NO_x removal, but their requirements for water offset that single advantage.

More recently, EPRI has tested the SCR process at the Institute's Emissions Control and Test Facility in Denver, Colorado. Dan Giovanni, manager of EPRI's Air Quality Control Program, comments, "The SCR process appears to be very effective in removing NO_x—up to 80%. The real issues are cost and overall power plant reliability. SCR equipment must be placed between the boiler and the air preheater, upstream from SO_2 and particulate control devices. The adverse impact of the SCR process on equipment performance and reliability downstream may negate its benefits in NO_x removal."

Full assessment of the SCR unit, apart from its NO_x removal performance, must include its operating demands (such as ammonia requirement, catalyst life, and energy consumption), environmental impacts (emission of ammonia, generation of sulfates, change in fly ash resistivity), and plant system effects (fouling or deposition in air heaters). Integrated emission control pilot operations began in 1981 under EPRI sponsorship, and they are expected to better define these factors.

Technology transfer

Many NO_x control technologies are highly developed in Japan, where they are in extensive use. The circumstance suggests that control designs or hardware could be exported to the United States as straightforwardly as automobiles, calculators, and bicycles. But there are reasons that slow the transfer and make it less than automatic.

Japanese experience shows no quick consensus on any single approach or system design. Developments are being decided case by case, just as in this country. Japan's first postcombustion NO_x removal developments were for units that burn fuel oil or natural gas, so the SCR technology, for example, has been applied to only about 1000 MW of coal-fired generating plant capacity.

Even apart from NO_x reduction considerations, utility furnaces in Japan are typically more conservative (larger) than in this country so as to burn a wide range of imported coals without reaching slagging temperatures. This by itself inhibits NO_x formation and complicates independent evaluation of a design's specific NO_x reduction features.

Utility industry practice in Japan calls for more complex combustion controls and more elaborate maintenance practices (often by contract specialists). U.S. practice tends to routine maintenance by plant personnel and a minimum of burner control dampers. The differences are subtle, but they make it unlikely that U.S. adaptation of Japanese NO_x control technology will duplicate its performance or its cost.

Regardless of origin, however, technology for controlling NO_x emissions well below present U.S. regulatory standards is emerging. The processes are sufficiently well understood to make them work. The R&D challenge is to replicate them at the required scales of generating unit size, in cost-effective performance, and with assured reliability.

Flue gas treatment—the SCR process, at least—has an apparent edge in application abroad, despite its high cost. Combustion modifications, however, have the edge in cost and operability, largely because they do not involve additional plant systems and system effects. These appeals are persuasive to U.S. utilities, for whom capital is scarce and expensive, and whose customers understandably resist higher rates.

EPRI research, in cooperation with utilities and manufacturers, is beginning to establish accurate comparative information on the performance, reliability, and costs of both NO_x control options. ■

This article was written by Ralph Whitaker. Technical background information was provided by Michael McElroy and Michael Miller, Coal Combustion Systems Division.

International Cooperation in Energy R&D

Cooperation among nations in matters of energy research promotes a sharing of technical expertise and prevents unnecessary duplication of costly test facilities.

Through weaving the technical expertise that exists in other countries into its research programs, EPRI is following the lead of many governments in recognizing the growing importance of international energy cooperation. The participation by organizations abroad in EPRI's R&D projects is now commonplace. For example, EPRI is sponsoring a regenerable flue gas desulfurization (Resox) project for the design, construction, operation, and testing of the process at a site in Lünen, West Germany. A group of German companies is one of the contractors for the second phase of the project.

In England the Central Electricity Generating Board is the prime contractor for an EPRI study on atmospheric chemistry related to acid precipitation. As part of this project, a Royal Air Force plane, equipped with instruments to sample and analyze air pollutants, is being used to research the formation of acid precipitation. EPRI is a joint contributor with the U.S. Nuclear Regulatory Commission, Electricité de France, Atomenergi Ab of Sweden, and the Technical Research Center of Finland, among others, on critical discharge flow for light water reactor safety at the Marviken plant in Sweden. These are but a few examples of the growing linkage that exists among energy R&D organizations worldwide.

The U.S. government has been a major participant in international energy activities, which began in the 1950s with a desire to improve the climate for civilian nuclear energy. In 1953 the United States launched the Atoms for Peace program and began to share nuclear technical knowledge with other countries to promote the peaceful use of atomic energy. Under that program, the United States trained thousands of engineers and scientists from other countries in our national laboratories and universities. The government has also provided nuclear research reactors and other facilities to many nations overseas.

U.S. involvement in international nuclear R&D has more recently focused on safety analysis and regulatory agreements. International energy cooperation in nuclear R&D has a long and detailed history and will be the subject of a future Washington Report. The discussion here will highlight the cooperation currently under way in nonnuclear energy R&D, an area that has greatly expanded in the last decade.

Collaboration Through IEA

"There are several different things that can be done in a research collaboration," explains Jack Vanderryn, director of DOE's international program in technical cooperation. "One is through simple information exchange in the form of reports, international meetings, visits to other countries' laboratories, or through our scientists working in laboratories abroad. One preferred way of collaboration is what we call task-sharing, where several countries map out an area of research, discuss the unique capabilities of each country, and then decide which part of the research will be done by whom. Ideally, the task will fall out with each partner researching a piece of it. Then all the partners pool results. This is the easiest way to cooperate internationally because it doesn't involve any transfer of funds."

Vanderryn's office is the coordinating point within DOE for collaborative agreements with other governments, as well as

Prochnik

with international organizations such as the International Energy Agency (IEA). His office provides policy guidance, while the actual partners on a specific project are drawn from DOE's technical staff. The international program at DOE is closely tied with the domestic program, as it is in the nation's interest to have international programs that will bring new technologies into the United States and broaden the alternatives available in terms of future energy technologies.

In addition, international energy technology cooperation affects U.S. interests in a number of ways beyond the direct benefits to DOE's domestic program goals. Martin Prochnik, director of the Department of State's Office of Energy Technology Cooperation, is responsible for the interrelationship of technology cooperation and foreign policy objectives. His office identifies the foreign policy elements of potential arrangements for technology cooperation. These elements are then factored into the agreements. Prochnik's office also provides continuing guidance for agreements in force. In doing this, he works closely with industry as well as with DOE and other offices in the government having interests in this area, such as the Office of Management and Budget and the National Security Council.

Prochnik points out that technology issues have become important in determining the nature of relationships between countries. "In energy, as in other technical areas, issues such as research policies, technology transfer, patent rights, and nuclear safety color the attitudes nations and regions have toward each other."

Prochnik cites IEA as a good example of the importance of these international relationships. "No one who sat through the gas lines of 1973 failed to get the point that there is a connection between energy and international relationships. The existence of this organization serves to convey a message to both oil-importing and oil-exporting countries that there is a cooperative effort under way to reduce the political and economic vulnerability of participating countries to future oil shocks. The benefits of IEA R&D programs thus are linked to a broad strategy of countries working together to protect their vital interests."

IEA was formed after the Arab oil embargo of 1973–1974, when the Western industrialized nations of the Organisation for Economic Co-operation and Development (OECD) (with the exception of France) came together to discuss ways to protect their energy supplies should such an event recur. Out of these discussions, the International Energy Plan was drawn up, and IEA was created to administer the plan and provide for future long-term energy cooperation. Established in November 1974, IEA now has 21 member countries: Australia, Austria, Belgium, Canada, Denmark, Greece, Ireland, Italy, Japan, Luxembourg, Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States, and West Germany. The European Communities group also participates in the work of IEA.

Vanderryn

An autonomous body within OECD, IEA's budget in FY81 was approximately $9.8 million. The financial assessment of each member country is based on a percentage of gross national product, except for the U.S. contribution, which is limited to 25% of the total. IEA is located in OECD headquarters in Paris but has its own governing board.

Allan Wendt, acting deputy assistant secretary of state for international energy policy, explains that when IEA was founded, most attention was paid to the plan drawn up in the wake of the Arab oil embargo for international sharing of oil supplies. Although the sharing plans are still an important part of the IEA's work, greater emphasis is now being placed on using the operation of energy markets to cope with supply disruptions. In addition, the United States is seeking to persuade other IEA members to keep adequate emergency stocks of oil and other fuels and to price energy resources in accordance with market forces so that uneconomic prices do not lead to overreliance on any single energy source.

The IEA Governing Board, composed of government representatives from each participating country, makes recommendations to the member countries on carrying out the objectives of the agency and reviews international energy developments. U.S. representation on the Governing Board is shared between the assistant secretary for economic and business affairs of the Department of State and DOE's assistant secretary for international affairs.

Two specific programs set up by the International Energy Plan and administered by IEA involve emergency oil-sharing plans should the flow of imported oil be disrupted (which include interaction with industry groups) and a country-by-country review of domestic energy programs.

The annual domestic review program is undertaken by IEA's Standing Group on Long-Term Cooperation. Detailed questionnaires on future energy consumption projections and long-term energy programs are sent to each member country. Every other year an in-depth review is conducted and a team of representatives from member countries visits each country to further assess its energy policies. The process continues when energy experts from each member country appear before the Standing Group to answer questions on their country's policies. Recommendations are then offered on how the member country's policies and programs can help achieve overall IEA objectives. These reviews are published each spring.

One of the basic elements of IEA is the attempt to reduce member country dependence on imported oil through energy conservation, development of alternative energy sources, and energy R&D. To further this goal, the IEA Committee on Energy R&D was established to promote cooperative R&D activities.

IEA's 1980–1981 annual report showed 46 joint RD&D projects under way or planned. The projects under IEA focus mainly on nonnuclear R&D. This does not imply less interest in nuclear R&D cooperation, but the many bilateral and multilateral nuclear agreements make it less necessary for IEA to administer these projects. In addition, the Nuclear Energy Agency, also part of OECD, provides cooperation and sharing of nuclear information among its member countries.

Because there is no central IEA fund for R&D projects, each country participating in a project must assume a share of its financial support. This can be done through task-sharing, with each country bearing its own costs, or in the case of larger jointly funded projects, through the project participants' contributions to a common fund. Large international test facilities are usually jointly funded.

Joint Test Facilities

One of the largest jointly funded IEA projects is a pressurized fluidized-bed combustion facility at Grimethorpe, England. Designed to assess the combustion conditions of coal, the unit will provide technical data for future commercial application of pressurized fluidized-bed technology. The project was initiated in 1975 and is expected to continue through 1983. The participating countries in the Grimethorpe project are West Germany, the United Kingdom, and the United States.

U.S. industry is particularly interested in the experiments at Grimethorpe because fluidized-bed combustion is a reasonably near-term technology. Six or seven industrial participants in the United States have sent staff to work in the Grimethorpe facility, which is one way to get technical information fed back to U.S. industry.

Another large jointly funded IEA project involves two solar facilities in Almería, Spain. Participating countries in this project include Austria, Belgium, Greece, Italy, Spain, Sweden, Switzerland, United States, and West Germany. The two solar power plants, located on the same site, are using different solar technologies: one is a distributed collector system (solar farm) and the other is a central receiver system (power tower). By constructing both facilities on the same site, a direct comparison can be made under operational conditions of both solar technologies. At the distributed collector system, two different collector fields of approximately equal size are being used, composed of parabolic trough reflectors of short focal length. One field has 10 rows of 60 collectors; the other, 14 rows of 6 collector modules. A third field will be added later. Designed for a lifetime of 10 years, the solar farm is projected to deliver 500 kW (e) of power for about 2000 hours a year, which will be fed directly into the electricity grid.

The power tower test facility consists of an energy receiver located on a tower 43 meters above the ground at the focal point of 100 individual heliostats. The main feature of this particular solar tower is liquid sodium, which is heated to 530°C, as a heat transfer and storage medium. This plant is expected to deliver 500 kW (e) for 2500 hours a year. Vanderryn notes that DOE has been trying to involve U.S. industry in these solar projects and reports that one U.S. firm supplied the mirrors and control mechanisms for the power tower. Both of these test facilities are now operating and were dedicated last September.

Another form of joint R&D cooperation is where individual countries support one large test facility. Under such an arrangement, each country brings its own test equipment and personnel to the facility. "We have a good example of this type of cooperation in the area of fusion. The United States has a large test facility at the Oak Ridge National Laboratory for superconducting magnets," Vanderryn notes. "The United States is fabricating three magnets to be tested in that facility, and three other national groups, the Japanese, the Swiss, and the European Communities organization, are each fabricating one magnet. The six magnets, which feature different materials and designs, fit together in a geometric configuration in the test facility. Here again is a research situation where all the participants will share the results. The United States is shouldering the largest cost because we built the facility and Oak Ridge manages the project."

Also in the area of fusion energy R&D, West Germany has constructed a test reactor, Textor (Torus Experiment for Technology-Oriented Research), which is the first tokamak device to be completely dedicated to the study of the plasma-wall interaction that occurs in magnetic fusion reactors. The overall objective of this joint R&D is to assess the importance of the processes leading to the buildup of impurities and wall damage in tokamak reactors under different operating conditions. The United States is a joint participant in this project with Canada, Japan, Switzerland, Turkey, West Germany, and a commission of the European Communities.

Bilateral Agreements

Although the majority of U.S. multilateral collaboration efforts are under the aegis of IEA, the U.S. government also has bilateral agreements with other nations, which are originated for both political and technical benefits.

In general, bilateral agreements are worked out on an agency-to-agency basis between DOE and its counterpart agency in another country. But there also exist government-to-government agreements—a statement of political will to cooperate—initiated more for political reasons and usually worked out through the Department of State. Currently the United States is involved in 69 bilateral energy agreements, although not all of them are active. One example of a government-to-government agreement that provides great technical benefit is an umbrella agreement with the Japanese government for cooperation in several energy R&D areas. Signed on May 2, 1979, the agreement states that the cooperation will be undertaken through an equitable sharing of costs and benefits over the next 10 years.

Under this energy umbrella agreement, two specific projects are under way: a nuclear fusion project (Doublet III) and basic laboratory work on high-energy physics. The umbrella agreement calls for an exchange of scientists between the two countries, although both projects will be carried out in the United States. Japan has committed $70 million for the Doublet III project over the next 5 years.

Doublet III is the largest fusion device of its kind in the world and has been operated for DOE by the General Atomic Co. since 1978. After the Doublet III agreement was signed, a joint steering committee was established, consisting of scientists from DOE and Japan Atomic Energy Research Institute (JAERI), to oversee the management of the project. A team of seven JAERI scientists has gone to General Atomic to work on the project, and in return for Japan's investment in the project, Japanese scientists take over one of the three shifts of the reactor for their own program interests.

The United States and Japan have also agreed to cooperate in the area of high-energy physics. The two countries signed a formal agreement to exchange scientists in November 1979. During the 1980 fiscal year, Japan contributed approximately $5.7 million to the U.S. research program in high-energy physics, and Japanese scientists participated in experiments on the large accelerators located in this country.

The United States has initiated additional bilateral agreements on high-energy physics with the People's Republic of China. This cooperation began with the United States helping the Chinese build a new accelerator near Beijing. The Chinese government then sent nearly 200 scientists to study and work in U.S. accelerator laboratories. DOE is also talking to the Chinese about cooperation in fusion, nuclear physics, and fossil energy (coal conversion and shale oil).

Another U.S. bilateral agreement involves a solar energy project with Saudi Arabia. This is a large program, with funding of about $100 million over five years. For the past three years, the United States has been operating a large photovoltaic array in a Saudi village. In addition, the United States is conducting research on solar-desalting technology and solar cooling, although the solar-cooling work is mostly done in the United States. Each partner in the agreement is putting in $50 million. Since a large fraction of the funds are spent in the United States with U.S. contractors, this agreement helps us advance our own programs. Vanderryn comments that such agreements also help us understand how certain technologies can be applied in developing countries: "For example, we also have a solar project in Gabon, a country in West Africa, which is a half-megawatt photovoltaic demonstration project. It is just now being implemented in several Gabonese villages."

DOE does not have many energy R&D agreements with developing countries. At present, much of the cooperation with developing countries is undertaken by the Agency for International Development, through the Department of State, which has an $80 million technical assistance program with developing countries; many of those projects are in renewable energy.

Prochnik elaborates on this point, stating that the relationship of the United States and other industrialized countries to the problems of developing countries has also become a major policy issue. "Oil-importing developing countries have been hit much harder than we by the need to pay for high-priced imports. In some cases, a nation's political stability is threatened by its deteriorating economic position."

Prochnik notes that for such countries cooperation and assistance in exploiting new energy technologies have direct national security benefits. "While the United States and other industrialized countries are eager to help, there can be differences in view between the industrialized countries and the developing world on the most effective ways of providing this assistance." These differences most frequently touch on the role of the private and governmental sectors, improved access to desired technology, and the role of multinational organizations.

"Another area where foreign policy and international energy technology cooperation interact is when such activities represent a broader set of cooperative arrangements that tie countries together. Benefits of such cooperation appear most evident when other elements of the relationship are under stress. Our scientific exchanges have served to maintain communication between important communities and policymakers in such countries and to provide a framework for broader ties in the future."

Other Forms of Exchange

Scientific meetings are another important forum for international R&D exchange. In August 1981 the United Nations Conference on New and Renewable Sources of Energy, held in Nairobi, Kenya, brought together more than 4000 participants. The national representatives at the conference adopted a program of action, which recommended measures to accelerate the development of alternative sources of energy at the national level, including national energy resource surveys and strengthened education and training programs. One area targeted for priority attention was the enhancement of international and national R&D activities in many of the renewable forms of energy, such as solar, biomass, hydro, and geothermal.

Similarly, the 12th World Energy Conference will be held in September 1983 in New Delhi, India, with a general theme of energy, development, and the quality of life. The conference will address innovations in energy production and use, as well as the need for cooperation in energy matters. The World Energy Conference was founded in 1924 to promote the worldwide development and peaceful use of energy resources. EPRI is a member of the U.S. National Committee.

Beyond meetings, information is transferred through the exchange of government-sponsored research reports. In this, however, the United States is at a real disadvantage because there is a tradition in government-sponsored research that does not really exist in any other country: almost all our research results are published and made available to the public. The French government, for example, can call the National Technical Information Service in Oak Ridge and buy U.S. government-sponsored research reports. U.S. researchers cannot do the same thing in France or West Germany or England. So there is an inherent imbalance in terms of access to government reports.

Despite this imbalance in disseminating research results, Vanderryn believes the United States is definitely benefiting from its international agreements in energy R&D. "The United States has no lock on the market of technical know-how, knowledge, or ingenuity. Other countries are also beginning to spend a large amount of money on energy R&D, maybe not as much as the United States, but still a considerable amount. And these nations are clearly becoming our competitors in technology. Therefore, anything we can do to keep up with their technical developments in order to bring new knowledge to our own programs is beneficial. And I believe we are doing it very well." ■

This article was written by Christine Lawrence of the Washington Office.

Gasification Demo Moves Ahead

size

Increased funding commitments enable construction of the Cool Water gasification–combined-cycle power plant.

Development of synthetic fuels in the United States was advanced on December 10, 1981, when funding was assured for the start of construction of the nation's first power plant based on integrated coal gasification–combined-cycle (IGCC) technology.

This step was made possible when participants in the $300 million Cool Water Coal Gasification Program committed additional money to the facility and thus demonstrated the industry's strong support for IGCC power systems as a major potential coal-based electricity generation option.

Construction work has now begun on the demonstration facility, which is located at Southern California Edison Co.'s Cool Water generation station at Daggett, California, 11 miles east of Barstow. Using the Texaco coal gasification process, the facility is designed to process 1000 t/d of Utah coal to a medium-Btu gas for electricity generation in an advanced General Electric combined-cycle unit. Various other coals, including eastern varieties, will also be tested. Final engineering design of the plant is more than 50% complete.

The IGCC concept, with its modular application, will enable utilities to install new generation capacity in increments, which is manageable both financially and in terms of generation needs. Dwain Spencer, director of EPRI's Advanced Power Systems Division, notes that the technology also offers important environmental benefits: "This IGCC process has the capability for greatly reducing power plant sulfur emissions compared with conventional alternatives, which may significantly enhance the industry's ability to meet new environmental requirements that could arise from increasing acid precipitation concerns." In addition, the demonstration facility is expected to confirm that significantly lower NO_x and particulate emissions will also be achieved with IGCC plants.

The Cool Water project was officially initiated in 1979 by Texaco, Inc., and Southern California Edison Co. It was later joined by EPRI, Bechtel Power Corp., and General Electric Co. According to Spencer, numerous domestic and foreign commercial coal gasification projects are relying on the results of the Cool Water project to provide a firm design basis for commercial plants. Although a funding plan has now been assured, other organizations are still being invited to join the project and share in its benefits. ■

1982 R&D Budget Approved

At its regular December meeting the EPRI Board of Directors approved a 1982 research budget of $250 million, an increase of some $30 million over 1981 levels. Of this figure, $210 million is for ongoing projects and $40 million for new research efforts.

The spending levels represent a reduction of about 20% from projected R&D expenditures outlined in the 1981–1985 five-year plan. This reduction reflects adverse economic conditions in the electric utility industry. As a result of the reduced funding levels, all programs were scrutinized closely by using a set of standard criteria. This review resulted in a research program with a greater near-term focus.

In their report to the Board, EPRI planners warned that because of budget debates currently under way in Washington, some major demonstrations and facilities may be cancelled or postponed and serious funding shortfalls are possible in efforts jointly sponsored with DOE.

The Board also approved $45 million for program management and in-house research, $5 million for special studies, and $3.4 million for capital expenditures, bringing the total Institute budget to $303.4 million. ■

PCB Seminar

More than 320 representatives of utilities, universities, government, and industry attended a special EPRI seminar on polychlorinated biphenyls (PCBs) in Dallas, Texas, December 1–3. A total of 38 papers were presented on safe methods of PCB detection, disposal, and destruction.

PCBs are a group of organic compounds with high dielectric strength, stability, and heat resistance. These qualities led to widespread use of the compounds in insulating such electrical equipment as capacitors and transformers. In recent years, however, PCB manufacture has been banned by statute and by EPA regulation because studies indicate they may cause health disorders.

As a result of these regulations, PCBs are no longer used in new equipment, but millions of gallons of PCBs are still contained in older electrical equipment in use throughout the country. The safe detection and disposal of PCBs are being addressed by a $7 million, five-year EPRI research effort.

Results of the EPRI-sponsored work, as well as of research elsewhere, were reported at the seminar. Several incineration methods and new chemical destruction processes were discussed, and other ideas that have yet to be demonstrated were proposed. Proceedings of the meeting will be published in mid-1982.

"From our standpoint, the seminar was very encouraging," says Gil Addis, the EPRI project manager who coordinated the event, noting that attendance was among the highest ever for an EPRI meeting. "We saw a host of methods for destroying PCBs that appear to be effective and environmentally benign."

A questionnaire completed by seminar participants indicated a desire for another PCB meeting within the next two years. "Within that time," says Addis, "we expect EPA to clarify some of its regulations, and we will have something more concrete to respond to." He adds that EPRI work will continue to emphasize easy detection of PCBs in the field, easy detection of incipient capacitor failure, and inexpensive PCB destruction. ■

CALENDAR

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

FEBRUARY

15–18
Symposium: Environmental Concerns in Right-of-Way Management
San Diego, California
Contact: John Huckabee (415) 855-2589

MARCH

7–10
Sixth International Ash Utilization Symposium
Reno, Nevada
Contact: Ralph Komai (415) 855-2463

15–18
Seminar: Reliability Design of Single-Pole Transmission Structures
Blacksburg, Virginia
Contact: Phillip Landers (415) 855-2307

APRIL

5–8
Seminar: Reliability Design of Single-Pole Transmission Structures
West Lafayette, Indiana
Contact: Phillip Landers (415) 855-2307

MAY

3–7
Planning and Electrical Design of Transmission Lines
Lenox, Massachusetts
Contact: John Dunlap (415) 855-2305

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

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

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

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

JULY

6–8
Fossil Steam Turbine Blade Problems and Improvements
St. Louis, Missouri
Contact: John Parkes (415) 855-2451

R&D Status Report
ADVANCED POWER SYSTEMS DIVISION

Dwain Spencer, Director

AIR-COOLED GASIFICATION–COMBUSTION TURBINE PLANTS

EPRI's Advanced Power Systems Division is assessing combustion turbine power plant configurations that use air instead of water for all plant cooling requirements. Two studies in this area, conducted by General Electric Co. and Ralph M. Parsons Co., have recently been completed (RP986). The objective of these conceptual studies was to determine the performance characteristics and costs of power plant configurations integrating coal gasification and combustion turbines when conventional air-fan cooling is used to cool all condensers and all process streams.

The principal reason that air-cooled power plants using combustion turbines might be competitive with conventional, water-cooled coal-fired steam plants is that a majority of net power is produced by the combustion turbines, which require no cooling water. Thus the cost and performance penalties entailed by air-cooling the bottoming steam cycle condensers are minimized.

General Electric performed cycle analyses to optimize the performance of air-cooled coal gasification–combustion turbine power plants. It studied configurations integrating three different coal gasification systems with combustion turbine–steam turbine combined cycles, regenerative simple-cycle combustion turbines, and nonregenerative simple-cycle combustion turbines. The gasification systems used were those of Texaco, Inc., British Gas Corp. (BGC), and Combustion Engineering, Inc. (C–E). The results of the analyses are reported in AP-1844. Coal-to-net-busbar efficiencies are shown in Table 1.

Table 1
GASIFICATION–COMBUSTION TURBINE PLANT EFFICIENCIES

Gasifier	Power Cycle	Efficiency (%)
Texaco	Simple	24.5
BGC	Simple	29.0
C–E	Simple	27.6
Texaco	Regenerative	26.9
BGC	Regenerative	32.4
Texaco	Combined (air-cooled)	34.2
BGC	Combined (air-cooled)	36.3
C–E	Combined (air-cooled)	33.9

Four configurations—the regenerative and combined cycles based on the Texaco and BGC gasifiers—were selected for conceptual design and cost studies by Parsons. For purposes of comparison, Parsons also developed design and cost estimates for a water-cooled Texaco gasification–combined-cycle plant. EPRI staff then calculated busbar revenue requirements for the Parsons configurations and for a conventional coal-fired steam plant. Major results are presented in Table 2.

Although the figures for the air-cooled plants are attractive in comparison with those for the water-cooled plants, the results might appear somewhat mundane. However, when it is considered that air-cooling a conventional coal-fired steam plant could cost up to \$300/kW, it is clear that an air-cooled plant using coal gasification and combustion turbines could offer considerably lower capital and busbar costs in situations where dry cooling is desirable.

As explained below, the results presented in Table 2 might be improved in the future as a result of developments in the following areas: combustion turbine firing temperatures, advanced combustion turbine cycles, dry-cooling technology, and NO_x control.

The Parsons analyses are based on a combustion turbine firing temperature of 2000°F (1093°C), which is representative of the temperatures of commercially available turbines. R&D is being conducted to increase combustion turbine temperatures, and it is generally expected that these efforts will be successful. If they are, the fraction of power produced by the combustion turbines in a combined cycle could be increased, which would have three favorable effects: a reduction in air-cooling capital costs; an increase in thermal efficiency, thereby reducing coal and gasification system costs; and a reduction in the unit capital cost of the combustion turbines because of a considerable increase in power output for a given frame size. Advances in combustion turbine temperature would also increase the thermal efficiency of regenerative combustion turbine plants and reduce the unit capital cost of the turbines.

New combustion turbine cycles, particularly the intercooled compound cycle, could also appreciably increase the fraction of combustion turbine power in a combined-cycle plant.

EPRI's Coal Combustion Systems Division is conducting tests of the ammonia-phase-change dry-cooling tower, which promises to be considerably lower in cost than conventional air-fan cooling. Use of this tower could reduce capital costs and perhaps increase thermal efficiency for gasification-based combustion turbine power plants.

Of the water consumption shown for the air-cooled combustion turbine–based plants in Table 2, about 800–900 gal/min (0.050–0.057 m^3/s) per 1000 MW is injected into the combustion turbines for NO_x emission control. If NO_x control can be effected by changes in combustor design rather than by steam injection, this quantity of water will not be required. *Project Manager: B. M. Louks*

Table 2
COMPARISON OF AIR- AND WATER-COOLED POWER PLANT CONFIGURATIONS

	Cooling Method	Efficiency (%)	Total Capital Cost (1980 $/net kW)	Levelized Cost of Electricity (mills/kWh)*	Water Consumption per 1000 MW (gal/min; m^3/s)	
BGC gasification–combined cycle	Air	33.3	1010	81 3†	2450	0.1546
BGC gasification–regenerative cycle	Air	30.3	1053	87.8†	2694	0.1700
Texaco gasification–combined cycle	Air	34.3	1171	85.5	1894	0.1195
Texaco gasification–combined cycle	Water	35.8	1085	81.3	6920	0.4366
Conventional coal-fired plant	Water	34.2	1030	90.6	11,150	0.7034

*Calculated by using promulgated 1981 EPRI *Technical Assessment Guide* methodology and criteria. Includes effects of 8.5%/yr inflation after plant startup.

†Credit not taken for hydrocarbon by-products. If credit were taken at a selling price of $3 per million Btu (1980 $), these costs would be 74.6 and 80.5 mills/kWh, respectively.

R&D Status Report
COAL COMBUSTION SYSTEMS DIVISION

Kurt Yeager, Director

DETECTION OF WATER INDUCTION IN STEAM TURBINES

Water induction into steam turbines can cause turbine blading damage, rotor distortion, and other thermally induced stress conditions. Present sensing systems using thermocouples seldom provide adequate warning of impending induction incidents. EPRI is therefore conducting research to develop an on-line monitoring device capable of detecting water induction incidents as they occur. The objective is to demonstrate the feasibility of using transducing systems to quickly detect the occurrence of water induction events in operating power plants and to develop a complete on-line water induction monitoring and diagnostic system. This system will enable utilities to identify the cause of water induction and to take corrective action to reduce the severity of incidents. Laboratory and in-plant evaluations have been made by Westinghouse Electric Corp. (CS-1604). Based on this work, it appears that passive acoustic transducers coupled with a digital data acquisition system will provide a greater capability to detect water induction events.

Water induction characteristics

During recent years there has been an increase in the frequency of incidents involving the induction of water or cool vapor into steam turbines. This inflow into a turbine can occur at various locations as a result of equipment malfunction in the heat cycle. Points of entry include main steam inlet piping, hot reheat steam inlet piping, cold reheat steam piping, extraction connections, gland steam sealing system, and turbine drains. The resultant structural damage, mechanical malfunctions, and outage time are of utmost importance to the utility involved.

The most common water incident is the induction of fluid into a steam turbine zone from external sources. In nuclear turbines, water accumulation can occur and cause major damage. The majority of water incidents occur during transient conditions (i.e., shutdown, startup, trips, and large load swings), but water incidents can also occur under steady-state constant load conditions.

Conventionally, thermocouples are used to detect water or cool vapor. Generally, however, the response time of thermocouples is such that once the metal temperature has lowered sufficiently to substantiate that water or cool vapor has entered the system, there is little chance that action can be taken quickly enough to prevent damage to the turbine.

To aid the utility industry, EPRI initiated work to develop an on-line monitoring device capable of detecting water induction incidents as they occur. To date, two phases of the work have been completed in which acoustic, pressure, and thermocouple transducers have been tested in the laboratory and in the field. Results from the testing indicate that passive acoustic transducers coupled to a digital data acquisition system should provide a reliable water induction monitor because of their excellent transient response, reliability, and nonintrusive nature. Pressure and thermocouple transducers were eliminated because of inadequate reliability and transient response characteristics. A third phase began in mid-1981 to demonstrate the operation of a field-ready, automatic water induction detection system in an operating plant. The goal is to produce a commercially available system.

Laboratory testing

During the laboratory phase of the project, four sensing methods were tested to determine if any had greater sensitivity and more rapid response to water induction than the usual thermocouple system: an active acoustic system; a passive acoustic system; a piezoelectric pressure transducer system; and a fast-response thermocouple system. The laboratory test program was divided into two parts. For detecting water backup in pipes, a series of static tests were performed in a vertical cylinder. For detecting slug, particle, chunk, and film flows, a dynamic flow loop was constructed into which water, steam, or both could be injected.

The water backup test apparatus consisted of a 3-ft (914-mm) vertical section of 16-in (406-mm) schedule-30 steel pipe. Two pressure sensors, two thermocouples, and two active ultrasonic water detectors were located on the periphery. Two sets of tests were conducted, using the following water conditions.

- Room-temperature (72°F; 22°C) degassed water to ensure minimum microbubble population and minimal thermal differential between liquid and sensors
- Hot water (112°F; 44°C) to test the response to microbubbles and large thermal differential between liquid and sensors

For these water conditions, the active acoustic method was found to be superior to the pressure and temperature sensors in that it did not require an accompanying temperature variation. In addition, the acoustic sensors were nonintrusive (i.e., pipe wall penetrations were not required).

A major facility complete with steam and water pipes; horizontal and vertical test sections; desuperheater; various valves; and facility pressure, temperature, and flow measurement instrumentation was designed and built for the dynamic laboratory water induction detection tests (Figure 1).

The loop operated at a maximum temperature of 600°F (316°C) and a maximum pressure of 600 psi (4.1 MPa). Glass viewports to help confirm the presence of film flow were included. Several sets of the test transducer were strategically located on the flow loop.

The loop tests simulated the following: water film flow, particle flow, and slug flow in the vertical leg of the loop; chunk flow and slug flow in the horizontal leg of the loop.

All three sensing methods (passive acoustic, dynamic pressure, and thermocouple systems) were found to be sensitive to film, particle, and chunk water flow in a steam flow. The poor transient response of the thermocouple system made it ineffective for detecting intermittent or transient water conditions. The dynamic pressure system could detect the presence of water in any form in steam piping. Its major disadvantage was that it required the water to be at a different temperature from the steam for it to be detected. The passive acoustic system was found to have an excellent transient response and an excellent steady-state response.

Based on these test results, it was decided to test the passive acoustic, the thermocouple, and the dynamic pressure transducer systems in the steam turbine piping of the New Boston station of Boston Edison Co.

Field testing

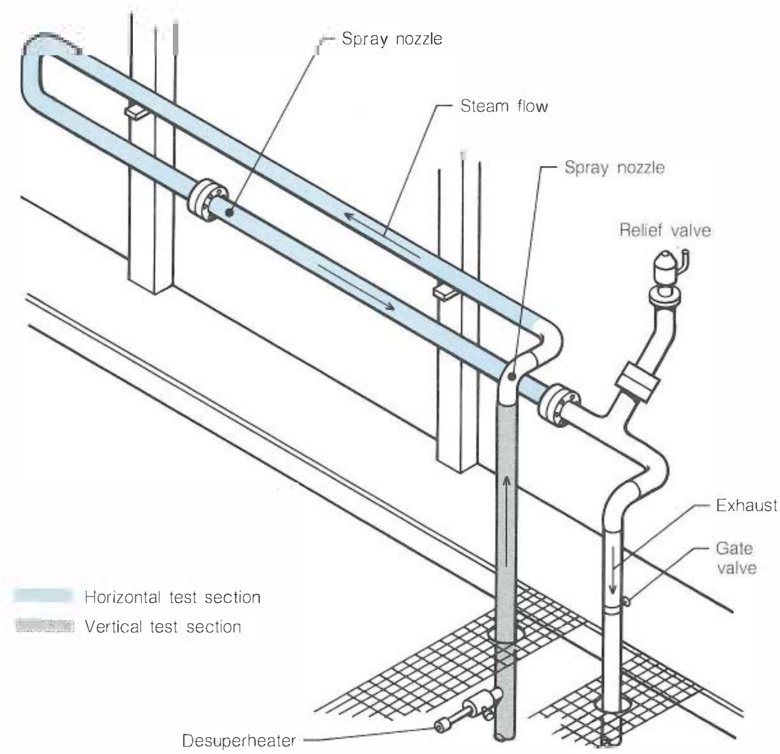
The objectives of this phase were to perform life tests of all instrument components under actual field conditions; to determine if the overall monitoring system, including the digital data acquisition system, would operate unattended over long periods of time and yet preserve important events; to determine the response characteristics of all instrument systems used; and to develop water induction signatures for use in future applications.

External control of the types of steam-water flows was not possible. However, each of the sensing system packages was exposed to representative types of steam-water flow by the judicious choice of installation location. Figure 2 shows the location of each sensing system package in the plant cycle.

Outputs from 17 water detection sensors and from 5 station pressure instruments were recorded simultaneously on a high-speed digital data acquisition system. This system was programmed to preserve signals from all channels for a period of 30 seconds prior to and 30 seconds after a triggering event.

Acoustic data from an event that was believed to be a water induction were detected

Figure 1 Horizontal and vertical sections designed for the dynamic laboratory water induction detection tests.



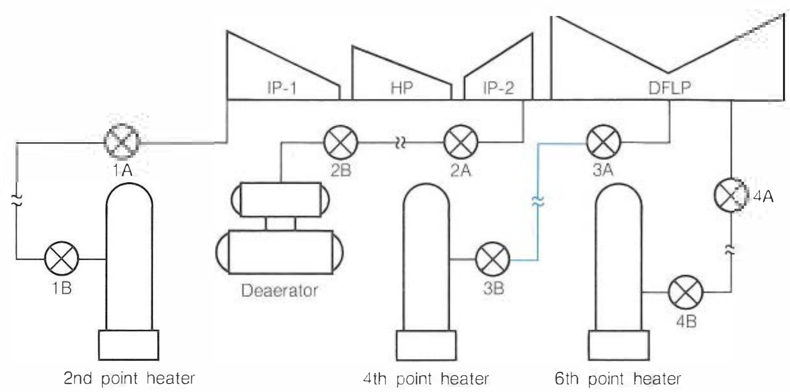


Figure 2 Acoustic sensors on the 4th point extraction line detected a transient signal at 3A and, one second later, at 3B.

by two sensors located on the 4th point extraction line and were recorded. A pair of transient signals were first detected at the upstream site (3A) and were again detected at the downstream site (3B) approximately one second later. These data are believed to indicate a water induction event for several reasons. The observation is consistent with the concept that water signatures (transients) should appear sequentially at measurement sites spaced along the pipe; delay time of one second indicates a water velocity of 100–150 ft/s (30.48–45.72 m/s), which is typical of expected steam velocities in this conduit; and recorded data indicate that steam flow began to increase at this time, perhaps sweeping some accumulation of water downstream.

Station records did not confirm that a water event occurred over this time interval. The reason for this is believed to be the much higher sensitivity of the experimental system.

Field test results and future efforts

Based on the utility phase of testing, the following conclusions were drawn.

- The field-tested water induction sensing systems show high promise for future monitoring systems. However, no confirmed water induction occurred in the utility installation during the test period, and therefore no opportunity occurred to test the water induction detection techniques.

- Field testing of the thermocouple system showed that care must be taken to ensure that the thermocouple well is free of debris, such as thermal insulating material; thermocouples are grounded in the well; only shielded thermocouple wire is used; and the thermocouple system is recalibrated every 6–12 months because of system drift.

- Field testing of the dynamic pressure systems showed that they did not operate reliably in a plant environment. Consequently, this sensing system is not recommended for future water induction applications.

- Passive acoustic systems were shown to have excellent transient response, to have high reliability in a harsh environment, and to be most desirable because of their nonintrusive nature.

- The digital monitoring and storage system proved satisfactory over the one-year period of its operation. However, experience with the system installed at the Boston Edison station indicated that several changes would be desirable for a commercial monitoring system.

Additional field testing is being planned to verify the usefulness of the subject sensing methods under actual water incidents that will be simulated in safe and realistic portions of an operating turbine cycle. It is expected that realistic signatures of actual water events will be developed from these tests.

It is believed that such work will form the basis for a water induction monitoring system to warn plant operators of the presence of water before it enters the turbine. This would allow the operator to take corrective action prior to damage in the turbine. A preliminary design for such a system has been developed. *Project Manager: John Parkes*

SPRAY DRYING FGD PILOT PLANT

Utility interest in spray drying for SO_2 and particulate control has increased dramatically in response to vendor claims for the process—easy-to-handle dry wastes, simplicity, and lower costs and energy requirements—plus newly promulgated federal emission regulations with lower SO_2 removal requirements (70%) for low-sulfur coals. Unfortunately, only limited data are available for use in evaluating vendor claims before commercial commitment or in improving the cost and reliability of this potentially important flue gas desulfurization (FGD) option. Accordingly, EPRI is conducting a pilot-scale project to provide a systematic evaluation of the technology that will be unconstrained by specific vendor designs, operating philosophies, or commercial operating limitations (RP1870). This evaluation will result in guidelines for system design and optimization in order to ensure reliable utility operation at minimum cost.

The utility industry has recently made a large commitment to spray drying FGD systems. The total capacity of these systems contracted to date is approximately 4000 MW, which represents 6.5% of the U.S. coal-fired generating capacity committed to FGD. This commitment to dry scrubbers is unusual, considering that the contracts were awarded before any commercial systems were operational at a utility power plant. However, the technology may offer significant advantages if it proves to be applicable.

The use of spray dryers for FGD is a new application of an old technology. In this case, the concern is not just with drying a product but also with absorbing SO_2. Typically, in FGD applications, a slurry of water and lime is sprayed through an atomizing device, usually a rotary atomizer, into the drying vessel. The flue gas is introduced cocurrently with the atomized slurry. SO_2 is absorbed into the slurry as the slurry droplets dry. The dry product leaves the bottom of the drying vessel and is fed into a particulate collection device, either a baghouse or an electrostatic precipitator (ESP). Some of this product is usually reslurried and recycled to the spray dryer to minimize the alkali requirement.

Spray drying is claimed to have several advantages over conventional wet scrubbing. The dry product is easier to handle during disposal, and when water is added, the solids undergo a cementlike reaction to form a material that is said to be suitable for landfill and capable of preventing significant leaching. Also, because not enough water is added in the spray dryer to saturate the flue gas, the exit gas should not need to be reheated to prevent condensation. The heat rate penalty for flue gas reheat is approximately 200 Btu/kWh, which represents the largest single energy requirement of an FGD system. Finally, the spray drying system envisioned by suppliers is simpler and uses less expensive materials than a wet scrubber. These two advantages would lead to lower capital costs and lower maintenance and energy requirements.

None of these claimed advantages has been verified at commercial scale, however, and there are several other uncertainties regarding application of the technology. Areas of technical uncertainty include the controllability of the flue gas outlet temperature to prevent wet solids from entering the particulate collection device; the quantification of SO_2 removal in the baghouse; the effects of solids recycling on alkali utilization; and alkali requirements for a given level of SO_2 removal. There are also serious questions about the integration of the spray dryer and the baghouse, the preferred particulate collection device. No work to understand their interactions, much less to quantify or optimize them, has been reported. Two problems with existing baghouses involve controlling pressure drop across the bags and setting the optimal cleaning cycle. It is not known whether there are corresponding problems for a spray dryer–baghouse combination. The other particulate option, an ESP, may also experience significant problems if solids from the spray dryer are wet and form a coating on the ESP plates.

EPRI has initiated efforts to resolve these questions under carefully controlled pilot-scale conditions and to develop the technical basis necessary for confident, reliable commercial application of spray drying–particulate control technology. Current EPRI spray drying work consists of four projects: a technical planning study to summarize the commercial design and identify the technical issues needing resolution (TPS80-741), an evaluation of the waste from vendor pilot plants to provide data with which to compare the EPRI pilot plant waste (RP1870-2), the pilot plant construction and startup effort (RP1870-1), and the pilot testing and evaluation effort (RP1870-3).

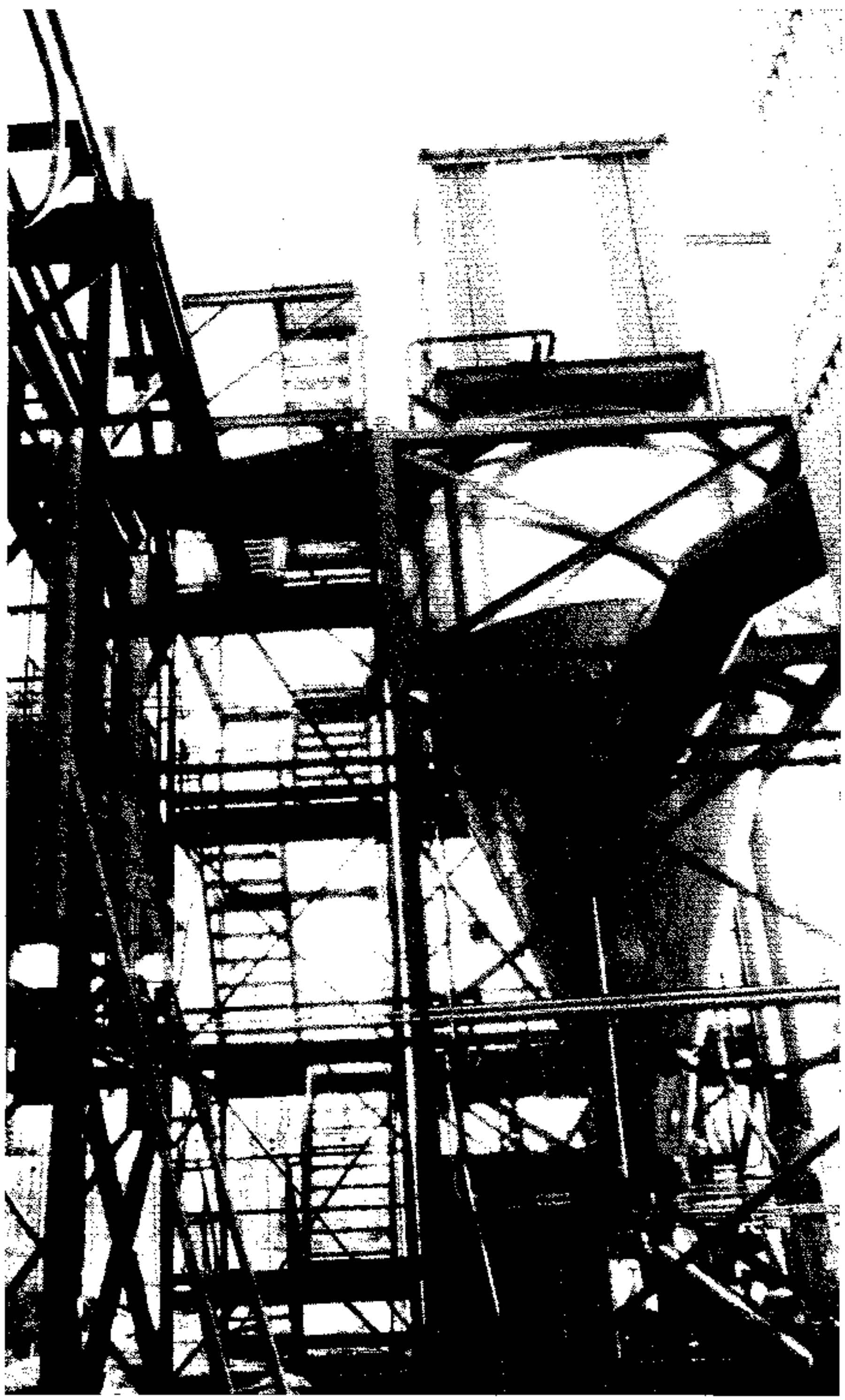
The 2.5-MW spray drying pilot plant is being installed at EPRI's Emissions Control and Test Facility at Arapahoe station near Denver, Colorado (Figure 3). Stearns-Roger, Inc., prepared the bid specification, and Stork-Bowen Engineering Inc. was the successful bidder. All major pieces of equipment were on site in October 1981. Startup was initiated in December and testing is scheduled to begin in January. Testing is expected to last approximately one year.

Considerable flexibility is designed into the facility. The 10-ft-diam (3.05-m) spray dryer test unit will have a single 60-hp (44.8-kW) rotary atomizer that can be replaced by a dual-fluid nozzle. The unit will also feature recycling of spent absorbent from the spray dryer, the particulate collection device, or both; gas exit from the vessel side or bottom; an alkali feed system capable of feeding sodium-, magnesium-, or calcium-based absorbents; a ball mill slaker and a paste slaker for the lime preparation system; vessel construction that will allow the gas residence time to be varied without a change in the gas flow rate; and operation with a baghouse or an ESP. Inlet flue gas conditions can also be modified: SO_2, SO_3, and ash can be injected, and the gas temperature can be controlled independently of the boiler.

The technical planning study on commercial design and unresolved technical issues has been completed and is scheduled for publication early this year. The results are useful for utilities contemplating bid specification or evaluation. They are also being used in determining pilot test condition priorities. For example, because most utility-ordered systems use rotary dryers, ball mill slakers, and baghouses, these will be featured in the first test configuration.

The waste solids work has proceeded slowly because of problems in obtaining samples from vendors. The samples are being processed in two batches. Preliminary results appear to confirm claims that when water is added to the waste and sufficient reaction time is allowed, the resulting product has high strength and low leachate values. *Project Manager: Richard Rhudy*

Figure 3 The 2.5-MW spray drying FGD pilot unit at EPRI's Arapahoe test facility.



R&D Status Report
ELECTRICAL SYSTEMS DIVISION

John J. Dougherty, Director

ROTATING ELECTRICAL MACHINERY

Application of induction generators

Recent progress in the development of controlled static volt-ampere-reactive (VAR) sources makes it possible to consider induction generators (coupled with controlled VAR sources) as technically feasible alternatives to the use of synchronous machines. The attraction of the induction machine lies in its simple, rugged, symmetrical rotor construction, without insulated windings, which results in a more reliable and less expensive piece of equipment than a synchronous machine.

The feasibility of using small-scale induction generators in power systems composed of predominantly synchronous generators is well known, but the performance characteristics of larger, high-efficiency induction generators whose voltage support is provided by static VAR sources has not been investigated. This was the subject of recently completed EPRI research (RP1945). Induction machines absorb a considerable amount of VARs, which must be supplied by the network, either from static capacitors or from other synchronous sources. Stability considerations determine the required range and control characteristics of the VAR sources.

In the course of the investigations, some basic questions on the nature of dynamic performance of induction machines had to be answered. The dynamic behavior of induction machines is governed by the interplay of inertial and flux-stored energies. Induction motors are generally of small inertia and have relatively small rotor time constants. As a result, it has become customary to neglect rotor flux transient effects in studies of motor behavior. In the case of induction generators, however, efficient designs imply large rotor time constants, and therefore the rotor flux transients play a very important part in transient performance. Turbine generator inertia also is large, compared with the inertia of a motor and its mechanical load.

An additional benefit resulting from the project was a much better understanding of induction generator dynamics, which derived from an exploration of fundamentals relating to modeling requirements, with or without rotor flux transient effects. The transport of power from synchronous and, alternatively, induction machines was also analyzed; a method of developing a transmission design that is reliable in either case has now been documented.

Although the investigation concentrated on large-scale induction machines, the results are equally applicable to small-scale generation, such as hydro, wind, and cogeneration. Further, although the emphasis was on induction machines with thyristor-controlled static VAR sources, the basic modeling and application work applies equally well to machines that either draw their reactive power from the network or use static capacitors for this purpose.

The advantages of induction generators over synchronous lie in lower first costs and—because of their simple, rugged rotor construction—higher expected reliability. In situations where the network is strong enough so that stability is not limiting (system short circuit greater than three times machine rating), the VAR requirements of the induction generator can be supplied inexpensively with switched capacitors, making the induction option economically attractive.

One of the specific scenarios studied involved generation and transmission from a remote location. This was evaluated in terms of the induction and synchronous alternatives. Although the induction option is technically feasible, given sufficient control VAR source range, the overall economics do not appear to justify use of induction generators in such situations because of the current high cost of thyristor-controlled static VAR sources. As the cost level for such equipment drops, the economic comparison could well change in favor of the induction alternative.

There are many other possible scenarios, however, and only a few are treated in the final report on this project (EL-2043). Each should be studied on its own merits, using the application methods and data resulting from this study. *Project Manager: J. C. White*

Improved motors for utility applications

An important project in the Rotating Electrical Machinery Program addresses the need to improve reliability and efficiency of powerhouse motors through advanced concepts and design techniques (RP1763). Efficient and cost-effective electric generation is directly dependent on the reliability and availability of motor drives for auxiliary equipment.

Motor drives for powerhouse auxiliaries (e.g., fans, pumps, compressors) account for a significant percentage of the total electric energy conversion in the United States. Improvements in electric drive efficiency would therefore have a most favorable effect on total energy consumption, thus increasing overall generation capacity.

A primary goal of the project is the identification and documentation of current reliability issues associated with powerhouse auxiliary motors. Information obtained from an industry assessment study (Phase 1 of the project) was the basis for identifying and developing new technologies or manufacturing techniques to improve reliability and efficiency (Phase 2). The information will also be used to determine if new modes of motor operation can be established to improve reliability and efficiency.

The industry assessment study has been completed. In this study, data on power plant motors have been collected from utilities that have a variety of classes of generating equipment (e.g., oil, coal, nuclear) and varieties of climates, geographic locations, and operating conditions.

The results of the industry assessment study were presented to the utilities in a workshop held on the subject in St. Louis, Missouri, September 24–25, 1981. The objectives of the workshop were to report to the utilities on the results of the industry assessment study; to discuss modes and rates of motor failures; and to hear utility suggestions on further EPRI-sponsored work to improve motor reliability, efficiency, availability, and maintainability.

The study found that 41% of the motor failures reported were bearing related, 37% were stator related, 10% were rotor related, and the rest (12%) were due to other causes. The study recommended, among other items, the need for motor failure data collection by the utilities on an industrywide, uniform basis; motor technology improvements, especially bearings and stator windings; and improvement in motor specification by utilities. Start of work on Phase 2 of the project is planned for early 1982. *Project Manager: D. K. Sharma*

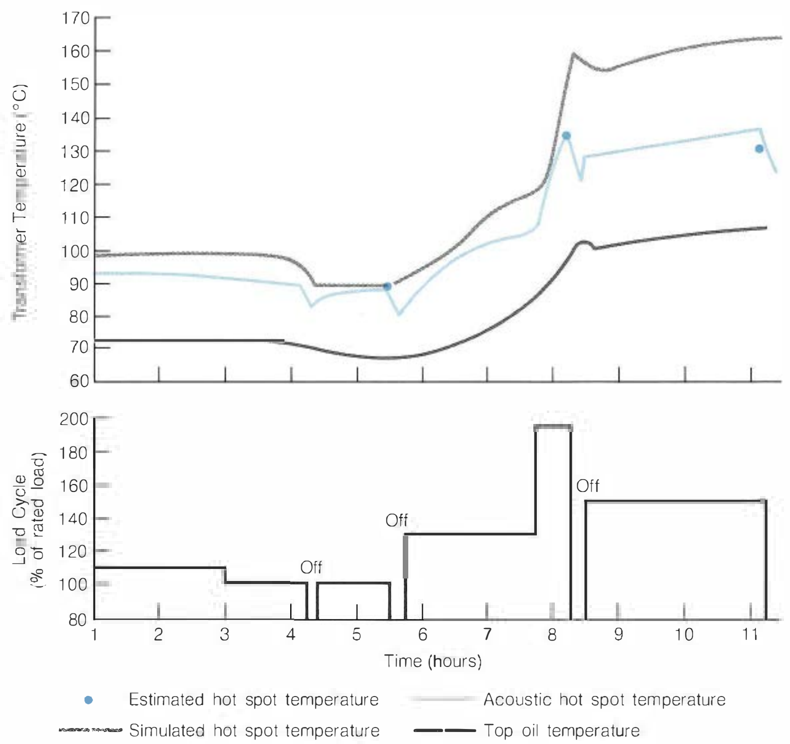
TRANSMISSION SUBSTATIONS

Passive hot spot detector

Transformer designers have long wanted to measure the winding temperatures of a transformer under load. However, no suitable temperature sensor has been available. Such a sensor must be small enough to be placed in direct contact with the winding material, capable of measuring temperatures up to 200°C, and be electrically isolated from the instrument used for temperature readouts.

EPRI is sponsoring the development of several different systems along this line. One of these, developed by Westinghouse Electric Corp. at its Sharon Transformer Division (RP994-1), consists of an ultrasonic temperature sensor, waveguides, and an electronics package suitable for both monitoring the transformer winding temperature and protecting the transformer as needed. Since last reported (*EPRI Journal,* March 1980), a sensor was installed in a 15-MVA, 67/12.45-kV transformer. The transformer, including the sensors and waveguides, passed conventional dielectric tests at the factory. This transformer was also subjected to a special overload test prior to its delivery to the utility. The essential results of this overload test are shown in Figure 1. The results are interesting because the measured

Figure 1 Transformer temperatures as recorded from a load test of a 15-MVA, 69/15-kV transformer with an acoustic hot spot detector installed on the low-voltage lead. The measured temperatures of the low-voltage lead are significantly lower than the estimated hot spot temperatures, based on resistance measurements and the temperature readouts of the conventional (simulated) hot spot gage.



temperature at one point in the transformer (believed to be among the hottest spots) was running significantly cooler than that indicated on conventional gages and was even below the calculated values. One test of this type, however, is not sufficient to support any definite conclusions because it is not possible to be absolutely sure the sensor was indeed placed at the hottest spot. As a minimum, several sensors mounted in one or more transformers are needed; these should then be subjected to actual operating conditions to prove the concept. The test did indicate that conventional methods for transformer temperature monitoring may be inadequate.

Unfortunately, this particular test transformer was damaged in shipment. As there were interference (cross talk) problems in the ultrasonic waveguide system, which affected the robustness of the installation, as well as its performance, it was decided to remove the waveguides from the transformer when the transformer was repaired at the factory. The original design of the temperature-measuring system relied on two waveguides: one for transmission of an excitation signal to the sensor and one for measurement of the sensor's response. To eliminate the cross talk that resulted, this design was changed to use only one waveguide. This, in turn, led to changes of the signal-processing system, which has now been implemented and tested. The test results indicate that the new design should work, and a new trial installation will therefore be attempted as soon as a suitable candidate transformer is found. Any test installation of this type, of course, will be done only with the approval of and in close cooperation with the utility that has ordered the transformer. It is anticipated that the next trial installation will take place in 1982. *Project Manager: Stig Nilsson*

Two-phase cooled power transformers

The first phase of this project resulted in two concepts, one by General Electric Co. and one by Westinghouse, for the design of a 50-MVA, 138/34.5-kV power transformer with load tap changing.

The General Electric design (RP1499-1) uses trichlorotrifluoroethane (Freon 113) as the fluid and employs sheet and strip copper windings to best utilize the heat transfer advantages of Freon 113. Windings can be condensed by either reducing or eliminating the cooling-duct spacings, thereby reducing the core window opening and consequently the core itself. The heat transfer improvement also increases the current-carrying capacity of the load tap changer, thereby eliminating the need for a series transformer at this rating.

The Westinghouse design (RP1499-2) uses tetrachloroethylene (C_2Cl_4) combined with transformer oil (75% C_2Cl_4 and 25% oil). The design is more conventional but uses reduced cooling-duct spaces and a less-expensive fluid.

The two conceptual designs have resulted in both companies projecting an evaluated cost (selling price plus evaluated losses) that is equal to or less than that of an oil-immersed transformer. As a consequence, both of these designs will be built as prototypes.

Empire State Electric Energy Research Corp. indicated a desire to place these transformers on New York state utility systems and agreed to share in the funding. The General Electric transformer will be designed to the specific needs of Niagara Mohawk Power Corp. as a 115/34.5-kV unit, rated 30/50 MVA, with load tap changing to be installed at its Courtland substation at the end of 1983. The Westinghouse transformer will be designed to the needs of Consolidated Edison Co. as a 132/13.8-kV unit, rated 33/66 MVA, with load tap changing for installation at its Seaport substation at the end of 1982.

Both utilities will conduct a two-year trial, with the installation of monitoring equipment developed by EPRI. The utilities plan to perform staged overload tests to demonstrate the operating characteristics of these transformers.

The commercialization of this new class of transformer with two-phase cooling on smaller sizes has already taken place. It is anticipated by both General Electric and Westinghouse that this technology will result in commercialization of a major portion of the medium power transformer requirements of utilities. *Project Manager: E. T. Norton*

SF_6 compact capacitors for ac and dc transmission substations

Capacitor banks are an important part of bulk power ac substations and dc converter stations, but they require a lot of space. As an example, a 400-MVAR shunt capacitor installation for a 345-kV transmission line may occupy a space exceeding 13,006 m^3 (140,000 ft^3). The capacitors themselves take up as little as 2% of this space, despite the fact that individual capacitor units are rated up to 200 kVAR. The large space required for capacitor banks is even more apparent in modern converter stations, where 30% or more of the converter terminal yard is required for the ac harmonic filter and shunt capacitor installation. The ac harmonic filters also account for a significant portion of the converter station losses.

EPRI and Consolidated Edison Co. of New York, Inc., are jointly sponsoring a project to develop a compact capacitor bank suitable for ac as well as HVDC stations (RP996). The development has been pursued under a contract with Brown Boveri Electric, Inc., which employed ASEA of Sweden as a major subcontractor.

Since the last report (*EPRI Journal*, December 1978), the work has resulted in successful factory testing of a 362-kV shunt capacitor engineering prototype, which has been used to verify the dielectric and thermal design assumptions. The prototype rack that is used to support the individual capacitor units inside the steel tank is shown in Figure 2. The mechanical soundness of the rack design has been verified by a shipping test.

The dielectric design of the new rack turned out to be much more difficult than originally anticipated because the geometry of the rack is very complex. A conventional capacitor unit is essentially a rectangular box with sharp corners, edges, and points, so careful shielding is needed to avoid excessive stress of the SF_6 gas. Careful selection of insulating materials is also required to ensure a long lifetime for the support structure. For these reasons, epoxy insulators and many aluminum shields (Figure 2) have been used.

One result of the design study is that it seems acceptable to reduce the impulse test level for the capacitor assembly down to the same level as is used for switching surge stresses because the capacitor will reduce the overvoltages normally associated with lightning surges by acting like a sink for the surge energy. Thus, if the capacitor is sufficiently large, the impulse test level can be reduced, which leads to cost savings as the dielectric shielding is then less critical.

Another identified benefit of the compact design (besides the space reduction) might be its significantly lower losses if the design is used for ac harmonic filters (the stability of a compact capacitor allows for a higher Q-factor of the filter). This translates into

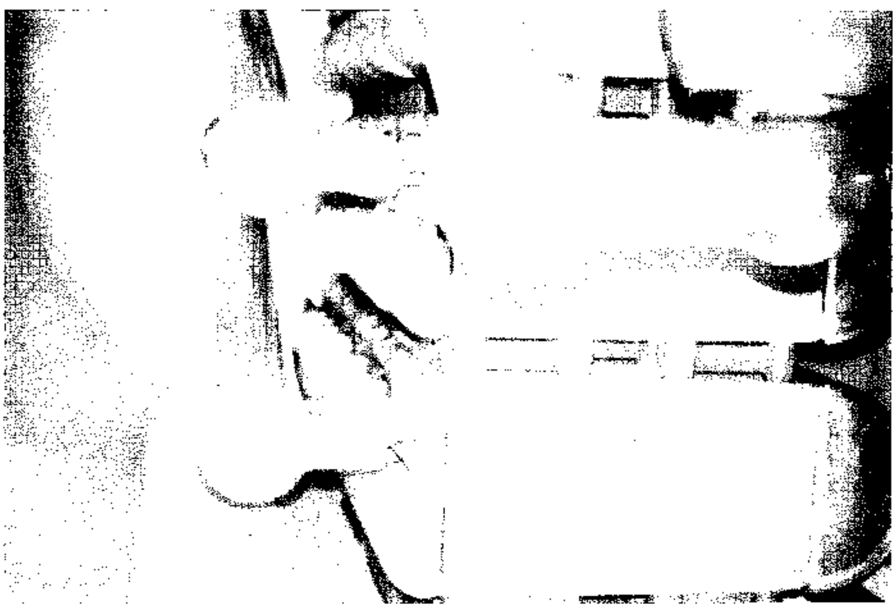


Figure 2 Compact capacitor bank inside a gas-insulated steel tank, showing the bottom two rows of the four-level capacitor support structure. In the foreground is the connecting bus between levels, and the bottom shield of the tank entrance bushing is visible in the top right corner.

a favorable loss evaluation for the compact design.

The design is now being evaluated for future demonstration of the technology. *Project Manager: Stig Nilsson*

OVERHEAD TRANSMISSION

Wind-induced conductor vibration

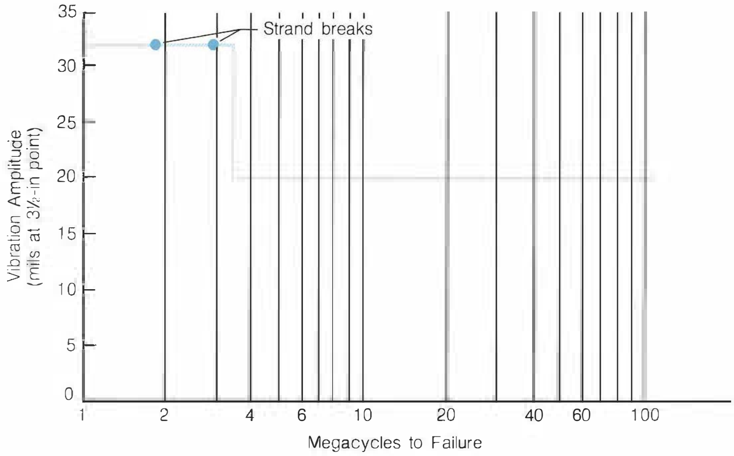
An earlier report (*EPRI Journal*, April 1980) discussed the initial work being done at Auburn University on damage to transmission line conductors from wind-induced eolian vibrations. The question addressed in this research effort is whether the addition of antivibration devices (dampers) to lines that had been minimally damaged by aeolian vibration would prevent further deterioration (RP1278). Three representative ACSR conductors were tested: a 4.03-cm² (795-kcmil) conductor with 26/7 stranding, a 4.03-cm² (795-kcmil) conductor with 45/7 stranding, and a 2.01-cm² (395-kcmil) conductor with 26/7 stranding. Eolian vibrations were simulated in the laboratory by inducing vibration in the conductor until one to three strand breaks occurred. The vibration amplitude was then reduced to simulate the addition of dampers, and vibrations were continued to determine if further breaks occurred. These initial tests were conducted for 20 million vibration cycles after the initial damage and showed no additional damage. This provided strong support for the effectiveness of this approach.

Since this initial work in Phase 1, test samples have been vibrated for 100 million cycles in Phase 2 to simulate the design life of the line. These tests also showed no deterioration after the simulated addition of dampers, providing further proof of the validity of the original conclusion. In addition, tests were made at different levels of vibration reduction to simulate several damper configurations. Results show that even a modest reduction of vibration amplitude will arrest strand breakage and allow the line to achieve its expected service life without reconductoring or splicing of the damaged sections (Figure 3). A final report on Phase 2 is being prepared and will be available early in 1982.

The present effort on Phase 3, just getting under way, seeks to further add to our knowledge of eolian damage to transmission lines by the following.

- Experimentally evaluating the effect of static bending and suspension clamp radius
- Experimentally verifying fatigue predictions for 4.03-cm² (795-kcmil) 26/7 Drake ACSR cables

Figure 3 Strand breaks in overhead transmission line conductor ceased after even a modest reduction of vibration amplitude; thus the expected service life of the Drake ACSR conductor was achieved.



- Experimentally evaluating the validity of Miner's cumulative damage hypothesis in predicting ACSR strand fatigue life
- Developing a probabilistic eolian fatigue design model for ACSR designs

This 30-month effort is expected to be completed by the end of 1984. *Project Manager: Joseph Porter*

Induced ac potential on pipelines

An outstanding example of cooperative research is a project jointly funded by EPRI and the American Gas Association (AGA) to develop mutual designs where overhead transmission lines closely parallel gas pipelines (RP742-1). The results of the initial project, which was completed in September 1978, were published in the final report, EL-904.

As a follow-up to this effort, both EPRI and AGA gathered comments and suggestions for additional needed research in this area, and in mid-1980 a follow-on project was funded by EPRI and AGA with Science Applications, Inc. (RP742-2).

The output of the current project will be a handbook for use by field personnel, containing simplified graphic computation procedures for typical situations of parallel power line–gas line operation and a computer program to perform analysis of complex parallel operation situations that can be used by persons with limited prior experience in such analyses.

Some of the tasks to be performed in the project are the following.

- Develop prediction methods for use with multiple pipelines located on the same right-of-way. Cases in which the pipelines are electrically connected will be included.
- Develop additional improved mitigation techniques and field-test them.
- Design data for pipeline protection during transient conditions.

The results of the initial project have been useful in developing mutual designs in several instances of parallel construction, and the results of the ongoing project should provide useful information on more complex situations, as well as provide additional mitigation techniques. *Project Manager: John Dunlap*

HVDC transmission line research at Lenox

The electric utility industry, EPRI, DOE, and General Electric have been partners in research at a unique testing facility in southwestern Massachusetts for many years. Even before EPRI and DOE existed, the Lenox facility was conducting R&D for EEI. In 1975 the Electric Research Council and EPRI published the popular *Transmission Line Reference Book, 345 kV and Above* (EL-100-1), based primarily on research at Lenox.

To meet an important anticipated need of the electric utility industry for the late 1980s and 1990s, the Lenox facility (often referred to as Project UHV) has converted its testing facility from HVAC to HVDC research. Here a program is under way to obtain the design information utilities will need to plan and construct HVDC lines (RP1282-2). Although the exact future of HVDC transmission is unclear at this time, the increasing number of announced new HVDC projects indicates that this emerging technology will be expanding rapidly. Further improvements in converter technology, emphasis on new generating sources remote from the load, and system stability considerations have caused many utilities to include HVDC as a viable alternative. Using HVDC transmission to uprate lines and to transmit more power along existing rights-of-way may become popular in land-scarce regions.

The EPRI-sponsored work at Lenox will produce a reference book for HVDC transmission similar to the one mentioned above for HVAC. Utilities planning for, or beginning design of, HVDC lines above the present level of ±400 kV cannot rely on experience from existing lines. Therefore, reliable design information based on extensive full-scale testing is needed to assure utilities that their future HVDC lines will perform as designed, while taking advantage of all possible economies.

The research at Lenox is concentrated on two main areas: electrical aspects of line design and insulation design. The design of towers, insulators, conductors, and ground electrodes is being done under other EPRI-sponsored projects; however, the entire HVDC effort is being coordinated and integrated by the Lenox project team. For example, new HVDC insulators developed in RP1206-1 are being tested at Lenox.

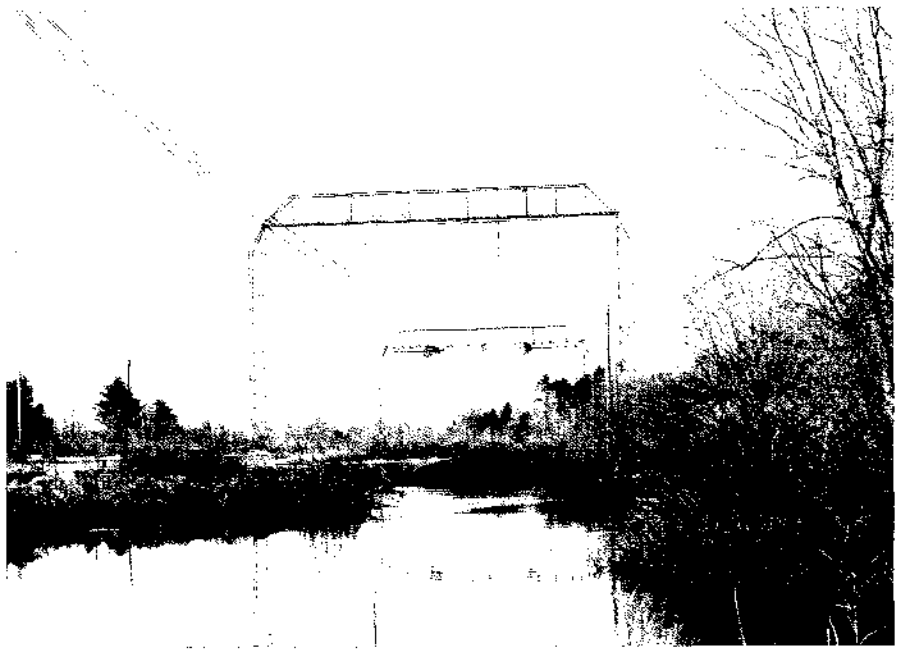
To obtain data on the operation of an HVDC line, the existing full-scale test line has been reconfigured from three-phase ac to bipolar dc (Figure 4). The first year of testing was at ±1200 kV, using a bundle of six 2.2-in conductors for each pole. This initial voltage level was selected to provide operating experience near the upper limit of the power supply and to determine if operation at this voltage level presented any practical limits for overhead HVDC lines. Operation of the power supply did present numerous problems during the first year; however, successful operation for several months indicates that the debugging process is over. Operation of the test line at ±1200 kV demonstrated that future lines up to this voltage level are technically feasible.

During the second year, the project team has investigated the industry's next anticipated commercial voltage level (±800 kV range). By varying line height, pole spacing, and voltage level on the test line through the annual variation of weather, measurements have been taken on audible noise, radio noise, TV interference, corona current, ozone, ion currents, and electric fields. Various conductor sizes and bundle configurations are planned for future tests.

The second main area of investigation, HVDC insulation design, has confirmed previous observations that insulators on dc lines perform quite differently than those on ac lines. The objective of the insulator research is to provide the line designer a means to select an optimal insulation design for the particular operating conditions of the line under consideration. Various insulator designs of porcelain, glass, and nonceramic materials are being tested in the fog chamber and on the test line. An artificial testing procedure is being developed that will closely match actual field operating characteristics. Again, initial work has shown a substantial difference between ac and dc in the design of a meaningful artificial testing procedure. This work is being coordinated with HVDC insulator research at the University of Southern California (RP1903-1).

A final report describes the conversion of the Lenox facilities from ac to dc (EL-1545). Of particular interest is the 1500-kV dc symmetrical cascade rectifier (Figure 5).

Figure 4 The high-voltage test line at Lenox, Massachusetts, has been reconfigured from three-phase ac to bipolar dc for testing between ±600 kV and ±1200 kV.



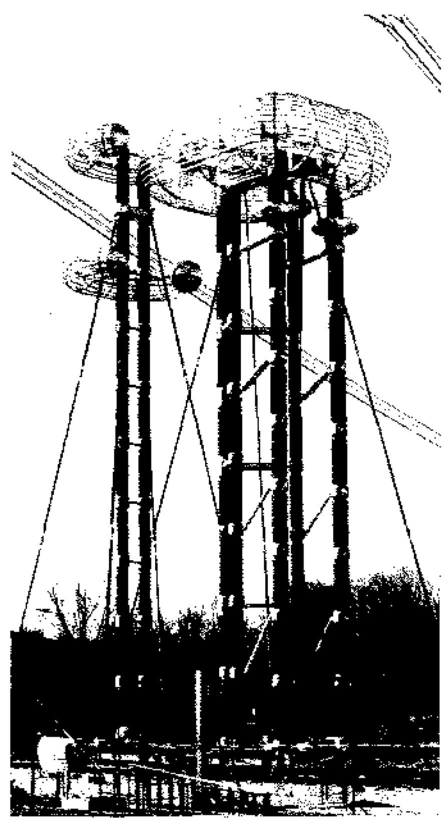


Figure 5 This 1500-kV dc symmetrical cascade rectifier set supplies one pole of the HVDC test line at Lenox, Massachusetts.

The publication *Transmission Lines, 345 kV and Above*, produced by the Lenox team, is recognized by the electric utility industry as an invaluable aid for EHV/UHV line design. The HVDC reference book currently being researched by the same team and scheduled to be published in 1984 is expected to fill the same needs for information on HVDC transmission line design. *Project Manager: John Dunlap*

DISTRIBUTION

Distribution automation

To those concerned with the energy supply segments of a utility system, the term *distribution automation* usually means a communication system at the distribution level that can control customer load. The peak-shaving capability of a load management system is very important to energy supply because it is this part of an automated distribution system that affects generation. It can lower the part of a system load curve that would require peaking generation to be brought on-line. With today's economy, any reduction in generation requirements, especially at the peaking level, could have a positive financial impact on a utility system.

To those concerned with the distribution system, distribution automation means a lot more than customer load management. It means that an unattended distribution substation could be considered attended through the use of an on-site microprocessor. It also means improved transformer loading at the substation level. This could result in deferred capital expenditures for additional power transformers, additional switchgear, and/or additional feeders. Advances in digital technology are making true distribution automation a reality.

The microprocessor (computer on a chip) can operate in the harsh environment of a distribution substation and, if so ordered, can make operating decisions and issue commands. As an example, a truly automated system can monitor substation and remote feeder voltage, as well as feeder VARs; it can then determine whether to add or subtract either voltage or VARs (or both) through an integrated system. The control processor can report this change in status to the distribution dispatch center (DDC), store it on-site for later use, or forget it, depending on the need of the utility.

An integrated automation system can control the feeder system during storm conditions. It may detect a faulted section of line, isolate it through automatic switching, backfeed the nonaffected feeder zones through tie circuits, and then report to a system operator that a feeder breaker had locked out because of a persistent fault, that the fault had been isolated between sectionalizing switches No. X–No. Y, and that service has been restored to all nonisolated areas and the breaker reclosed. The system operator would then know where to send a repair crew and even what equipment a repair crew might need (for example, A-phase down between switches No. X–No. Y). In most cases, all this will take place in a matter of minutes, or before the telephone starts to ring.

Digital systems, always considered beyond the reach of distribution, are rapidly becoming a reality. Digital protection should offer the distribution engineer protection flexibility never before available. The protection module can be a stand-alone device (does not depend on any other equipment), and can have self-diagnostics and the capability of calling the DDC to report that it is not functioning properly. Present-day electromechanical relays may be inoperative for an extended period of time, relying on either the transformer secondary protection or primary protection system to clear a feeder fault condition (which could result in from two to four times the number of customers affected by a single feeder fault).

If a digital protection device does become inoperative and fails to issue a trip command during a fault condition, a higher level of digital intelligence at the same station may be able to detect the "failed to operate" condition and issue a separate trip command. This could be considered breaker-failure protection, or redundant relaying at no additional cost. The protection module may be programmable for the various coordination characteristics that exist in modern relay devices, as well as have built-in automatic reclose and underfrequency protection capability. The capability of such systems is limited only by the imagination of the designers or the need of a utility.

General Electric is developing an integrated distribution control and protection system that uses microprocessor technology for installation in Texas Electric Service Co.'s Handley 138/12.5-kV distribution substation (RP1472). The substation processing units will interface with the following.

- Feeder remote units to automatically control the feeder system
- A communication system
- Transmission protection
- An existing SCADA system
- A colorgraphics CRT to allow dispatch operators to monitor that part of the system they may be concerned about

The system is being designed to allow modular implementation and should be placed in service in mid-1983. *Project Manager: T. J. Kendrew*

R&D Status Report
ENERGY ANALYSIS AND ENVIRONMENT DIVISION

René Malès, Director

LEGIONELLA STUDY

The well-publicized 1976 incidence of Legionnaires' disease in Philadelphia was associated with a hotel's cooling systems. Since that time, the bacteria responsible for the disease (Legionella pneumophila) *has been found to be wide-ranging, and other incidences of human infection have been reported. However, there is still little understanding of how and why such outbreaks occur. Because the largest cooling systems in the United States are in the electric utility industry, several utilities felt it prudent to examine whether power plant cooling systems harbor Legionnaires' disease bacteria (LDB). Accordingly, EPRI has initiated a project to establish if LDB occur in power plant environments and, if so, to identify the ecological factors that allow the bacteria to exist (RP1909).*

The LDB project is testing the hypotheses that the organism is ubiquitous and that ecological factors control its growth. The project is also investigating whether or not particular densities or strains of the organism are associated with the electric utility environment. If the research indicates significant numbers of LDB in power plant cooling systems, experiments will be conducted to establish the effectiveness of biocides in controlling the bacteria. Chlorine is known to reduce LDB numbers, but it is not known whether chlorine will eliminate the organism from a habitat.

The project is being conducted in two phases. A threshold level of 10^4–10^8 organisms per liter has been associated with most outbreaks of Legionnaires' disease. Therefore, Phase 1 consists of screening studies to identify the types of power plants and cooling systems where LDB levels in excess of 10^4 per liter may be found. Phase 2 will consist of studies of in-plant water conditions and microecological activities as they relate to the growth, development, abundance, and virulence of LDB. No human health studies are included in the project.

During Phase 1 extensive field sampling is being conducted for a year at nine U.S. power plants—four in the Midwest, four in the Southeast, and one in the East. Four plants have cooling towers, two have cooling lakes, and three are located on reservoirs and have once-through cooling systems. Six of the plants are coal-fired, and the other three are nuclear. At each plant water is sampled in the intakes, in the precondenser water box, in the postcondenser water box, and at the outfall. The samples, about 9 liters each, are collected once during each of the four seasons. Sampling began in March 1981.

The water samples are analyzed for physical and chemical properties and for LDB. Temperature, conductivity, and pH are measured, as well as the amounts of dissolved oxygen, ammonia, nitrate, orthophosphate, inorganic carbon, organic carbon, and total carbon in the water. For the LDB analyses, an 8-liter sample is first spiked with a tetrazolium chloride dye and then is concentrated 500-fold by continuous centrifugation at 8000–10,000 rpm at room temperature. A 0.01-milliliter subsample of the concentrate is placed on a toxoplasmosis slide, air-dried, heat-fixed, and mixed with specific-fluorescence antibody. The water sample is quantified for LDB concentration by counting the fluorescing LDB cells on the slide when viewed under a microscope with the appropriate light filters. This method of analysis is known as the direct fluorescent-antibody test. To determine the viability of the LDB, the same slide is viewed under a bright field microscope; the living cells are identified as dark inclusions.

Bacteria from a few water samples (selected on the basis of LDB densities in excess of 10^4 organisms per liter and also sampling location criteria) are being tested for virulence by guinea pig injection. The animals are injected with 2–3 milliliters of the concentrated sample. Those showing a temperature rise of 0.6°C or greater for two consecutive days, as well as those who have a lower temperature rise but show overt signs of illness (e.g., lethargy, watery eyes) within ten days of receiving the injection, are sacrificed for further analysis. Spleen samples are taken, and the fluorescent-antibody technique is used to determine LDB concentrations. Spleen samples are also cultured on special media (charcoal yeast extract agar or yeast extract broth) at 35°C, and the cultures evaluated for the development of LDB colonies.

During Phase 1 of the project, existing data on the structure of ecological communities are also being assembled. Preliminary statistical analyses of the data will be carried out to establish correlations between ecological and water quality variables and LDB characteristics.

On the basis of the first full year of Phase 1 work, the Phase 2 study design will be finalized. The major task of this phase is an intensive study of two to four of the Phase 1 plants to investigate the relationship between microflora and LDB. An association between LDB and certain algae is known to exist. Intensive water sampling will be done at each plant. To establish the major factors affecting LDB growth, microhabitat data will be analyzed and experimental culture studies performed. Emphasis will be placed on establishing the effects of dissolved organic matter and biocides on LDB growth, abundance, viability, and virulence.

A project advisory committee composed of EPRI, utility, and university scientists is reviewing the progress of the research and suggesting changes in its direction as appropriate. It is expected that this two-phase field and laboratory study will generate valuable data on the occurrence, growth, and virulence of LDB in power plant cooling systems and will establish the effectiveness of biocides in controlling LDB. The results will be useful to utilities in determining the potential for LDB in their cooling systems and assessing the need for control alternatives. Final results are expected to be available in late 1983. *Project Manager: Ishwar P. Murarka*

TEAM–UP

The ultimate measure of success of EPRI research is the extent of its application by electric utilities. The transfer of energy analysis models to utilities project (TEAM–UP) is a new, experimental approach to facilitating the transfer of models to the utility industry. The models, which were developed by EPRI's Energy Analysis Department, utilities, and others, can help utility planners respond to today's complex environment. However, EPRI and the utilities are uncertain about how best to achieve the successful transfer of these models and are trying diverse approaches.

Current activities

TEAM–UP activities are coordinated through a project office at Battelle, Columbus Laboratories, the contractor for this project (RP1814). To help utilities test and evaluate selected energy analysis models, TEAM–UP has been (1) operating a central interactive library of selected models for remote access, testing, and evaluation; (2) developing and making available standardized model documentations and user guides in a uniform format across models; (3) providing assistance to utility users interested in testing the selected models with utility-specific inputs; (4) demonstrating the capability to transfer machine-independent, standard copies of the models in the library for in-house utility use; (5) publishing a quarterly newsletter; and (6) conducting training seminars.

The TEAM–UP library, which resides on the Battelle-Columbus computer, may be accessed via computer terminal and telephone from anywhere in the United States. Access can be either by local dial-up to the TYMNET communications network or by a direct long-distance call to the Battelle computer.

The library is conversational (i.e., the user can "converse" in plain English with any of the models in the library). Users have several standard options: They can select the model and the model data base to be used, show and/or change model inputs, run model computations, show model outputs, and/or save the results of a model run for later use.

Limited funds have been set aside to allow EPRI member utilities access to the library. On request, each member is given a modest computer budget for library use. In return, each user is asked to provide feedback about the library to help the project team improve the system operation. Additional allocations of computer access time are considered case by case, based on the project work load and budget. Access procedures are available from the project office on request. (To date, over 70 utilities have accessed the central library models.)

User guides have been developed for each model in the library. The guide structure is standard for all models and contains references to methodologic documentation of the model (e.g., various EPRI reports) describing the initial model and data development process; a summary description of the model structure; a description of the model data base (both inputs and outputs); a description of the model code; and instructions on how to run the model.

To make it easier to use the models, TEAM–UP applies a standardization procedure to each library model. The model inputs and outputs are separated from the computation program and reside in a random-access data base. A supporting program—the host system, common to all models—performs data base management and report-writing functions. A user interface allows the user to direct the host system program to execute the available system options. This standardization process yields common access conventions for all models, together with uniform input, output, and documentation formats.

Two versions of the host system have been developed. The central host is part of the central interactive library on the Battelle-Columbus computer and facilitates the conversational user interface. A simpler command language is used in the local host system that is available for transfer to utilities for in-house use.

The host systems and standardized models have the desirable characteristic of machine independence—they can be executed on all commonly available large-scale computer systems with virtually no changes. To demonstrate the transferability of this methodology, the local host system and selected models have been distributed and installed on five utility computer systems.

Available models

The interactive library of selected energy analysis models is the core of TEAM–UP.

LSFM (load shape forecasting model). Developed by EPRI (EA-970), this model is based on an end-use and seasonal description of the daily load curve (for 10 end uses and 8 season/day–types). It generates alternative forecasts of the load shape and the load duration curves. These curves depend on electric demand growth assumptions and hourly use patterns for the end uses constituting the load curve. The model may be used to analyze the impact of new technologies (e.g., advanced batteries and heat- and cold-storage devices) on the load curve.

O/U (over/under capacity planning model). Developed by EPRI (EA-1117), this model provides a framework for evaluating alternative levels of planning reserve margins for power systems in terms of total costs to consumers under conditions of uncertain future demand. It uses system planning data, as well as judgmental estimates of demand uncertainty, environmental costs, and outage costs, to estimate total costs to consumers.

IPGFM (in-plant generation forecasting model). Developed by EPRI (RP942), this model forecasts the use of purchased and self-generated electricity in the industrial sector for each of the nine census regions for the period 1980–2000. Outputs at the state level are also possible. The model data base supports separate forecasts for each of four industries: SIC 26 (paper), SIC 28 (chemicals), SIC 29 (petroleum refining), and SIC 33 (primary metals). The principal objective of the model is to forecast how much self-generation is likely to occur in a state or region under a variety of economic conditions, electricity prices, fuel and equipment costs, and other financial parameters. The data base also contains detailed data by plant to analyze the economics of self-generation at the individual plant level.

POWRSYM (power system production costing model). This is the Tennessee Valley Authority's chronological probabilistic simulation production costing model. Power system operation is simulated by years in time steps of a year, a week, or an hour. Hourly chronology is maintained, and chronological constraints—minimum up and down times, ramp rates, pumped-hydro reservoir constraints—are simulated. Forced outages may be input externally in weekly increments, or they may be distributed weekly as deratings by using weekly loss-of-load probability as a levelizing objective function.

TCM (technology choice model). Developed by EPRI (RP1433, EA-2153), this model is designed to aid utilities in making decisions regarding the building of generating plants by weighing the costs and benefits of one type of plant against those of another. The model allows the decision maker to look at the possible consequences of his decisions and assign values to complex outcomes. The model permits the user to consider a number of associated factors (e.g., siting, licensing, and water requirements) in addition to economics. The model highlights the benefits associated with any decision route by allowing users to incorporate their own weights for the relative importance of the outcomes and probability assessments of the uncertainties.

RAM (regulatory analysis model). Originally developed by Temple, Barker & Sloane, Inc., this model is used to analyze utility financial data and projections of revenue requirements. The model is designed to make projections of the financial status of a utility by using a set of assumptions concerning demand, capital expenditures, operating costs, and financial or regulatory policies.

TEAM–UP is an important addition to the transfer methods currently being used, which include technical reports, conferences and seminars, and projects involving utility participation. For example, training seminars were conducted to demonstrate the operation of the system and provide instruction in its use. Attendees were given extended periods of hands-on access to the library models under guidance of the TEAM–UP staff. Twenty-five utilities sent a total of 30 representatives, most of whom have subsequently used the system, at least on a trial basis.

As explained above, TEAM–UP activities are primarily intended to help utilities test and evaluate selected energy analysis computer programs. TEAM–UP is designed to be complementary to EPRI's Electric Power Software Center, which focuses on code distribution and related verification activities.

Future plans

TEAM–UP is an 18-month demonstration effort, ending in April 1982. Its performance is currently being evaluated relative to the needs of the Energy Analysis Department and to alternative approaches to fostering research transfer. This evaluation includes extensive feedback from the users of the current system. Recommendations for future activities will be emerging from the Project Working Group, composed of utility and EPRI representatives. *Project Manager: Victor Niemeyer*

R&D Status Report
ENERGY MANAGEMENT AND UTILIZATION DIVISION

Fritz Kalhammer, Director

LOAD LEVELING ON INDUSTRIAL COMPRESSOR SYSTEMS

Industrial compressors represent a unique opportunity for large energy demand and cost savings. They are used in several major industries (e.g., chemicals, food processing, metals fabrication) and are significant energy consumers (8×10^{13} Btu/yr), but little has been done to maximize their efficiency through process-specific control strategies. Thus a project was undertaken to demonstrate the technical feasibility and cost-effectiveness of applying compressor system conservation and load management approaches, including optimized compressor control strategies and proven waste heat recovery techniques, to reduce peak load and save energy in industrial and commercial facilities (RP1088).

The project investigated (1) optimized compressor controller gain-reset strategies for matching the rate of compressor system response to specific load fluctuations or process changes, (2) specialized compressor modulation controls for optimizing suction, interstage, or discharge pressures and improving system efficiency, and (3) compressor waste heat recovery approaches.

Detailed data analyses and computer simulations were performed to develop and optimize a wide range of control strategies and to assess their use in combination with compressor waste heat recovery systems. The project examined the specific effects of applying these strategies in a large food-processing facility (a domestic brewery). In-plant trials were conducted to verify the analytic results and predictions under actual operating conditions. These trials provided a basis for determining specific implementation requirements (changes in existing compressor control strategies and set points and associated hardware and software); identifying potential production process or product impacts or sensitivities; and establishing implementation costs, savings, and payback periods.

Load management approaches

The more common approaches to energy conservation and load management for large industrial compressor systems fall into two categories: controls provided by compressor manufacturers as an integral part of the system design and controls added by owner-operators to better match compressor operation to their unique process requirements.

Controls of the first type include unloaders and hot gas bypass mechanisms. Because such approaches and their limitations are well known, they were not covered in this project. There are many conservation and load management approaches of the second type in practice today. Chief among these is the on-off cycling of large numbers of electric energy users by automated control systems. However, this strategy is applicable only to equipment whose operation is not critical to the process it serves. Because industrial compressor operation typically is vital, alternative methods are necessary for these systems.

A promising, although largely uninvestigated, approach of the second type is capacity modulation. This involves adjusting a compressor system parameter to maximize efficiency while satisfying the process requirements (such as compressed-fluid flow rate, pressure, and refrigerant temperature) for a given period. This strategy is called capacity modulation because as parameters are changed to improve efficiency, capacity is usually decreased.

An example of this method is the modulation of compressor system pressures—suction pressure, interstage pressures (when they exist), and discharge pressure. This is in sharp contrast to the widespread current industrial practice of setting these pressures at fixed values sufficient to satisfy the most stringent process requirements that will occur during compressor system operation. Although the current practice has the apparent advantage of greater ease of process control, inexpensive microcomputers are available that can perform system pressure modulations while maintaining process parameters at acceptable levels.

Study methodology

The development of practical compressor control strategies must take into account that industrial facilities are highly complex. Many pieces of electrical equipment are operated to satisfy varying and interrelated process requirements. An analysis based on simplifying assumptions, while tractable, may not produce realistic, usable results. Also, constraints on control strategies imposed by product quality considerations must be identified and incorporated into strategy development efforts. Therefore, to ensure that realistic strategies were developed under RP1088, it was necessary to select an actual facility from which operating data and information on product quality constraints could be obtained and where promising strategies could be tested.

Three criteria were important in selecting the industry of the model facility. First, it should use large, energy-intensive compressor systems amenable to capacity modulation control strategies and the application of waste heat recovery systems. Second, it should be a major industry so that the project results would be directly applicable to many facilities throughout the United States. Third, its equipment should be similar to that employed in many other industries to further extend the usefulness of the results. The widely dispersed food-processing industry satisfied all these criteria. Its refrigeration systems use large, energy-intensive reciprocating compressors that operate for long periods of time.

The Anheuser-Busch brewery in Tampa, Florida, was selected as the model facility. It has a large refrigeration system powered by several 300-hp (224-kW) heavy-duty compressors. The brewery process involves many energy-consuming operations typical of industrial plants: grinding, weighing, heating, cooling, filtering, and packaging. The need to rapidly cool large batches of freshly brewed beer (wort) provided an opportunity for introducing capacity modulation control; that is, process requirements for compressor system operation vary significantly, depending on whether wort is being cooled or not. In addition, the Tampa brewery represented an excellent candidate in that it is energy-efficient (its energy use per unit of product has been shown to be one-half that of similar-size breweries) and has a strong technical staff and excellent records of energy use. Because brewing companies are extremely conscious of product quality (i.e., consistently good taste), it was expected that strategies for energy conservation found acceptable at this facility would be readily adopted by many other sectors of the food-processing industry.

The complexity of the brewery process dictated the need for computer simulation to estimate the impact of changes in operation. Literally dozens of pieces of electricity-consuming equipment might be affected by such changes. Also, because of time and cost constraints, in-plant evaluations could be conducted for only the most promising of the many strategies under consideration. Thus simulations were needed to eliminate the less-effective approaches and those with potentially adverse impacts on the process.

Data on brewery equipment capacity and energy consumption were used in constructing a computer model. The actual energy consumption characteristics (both transient and steady state) of all equipment larger than 25 hp (18 kW) were measured and incorporated into the model. The model was validated by comparing its predictions with data on brewery operation and energy use.

Results

The results of this project indicate that significant cost savings can be achieved through optimized compressor control strategies. Specifically, the use of optimized controls at the brewery resulted in savings of $76,000–$82,000 a year with minimal implementation costs (less than $5000). These cost savings are based on annual electric energy savings of 2100 MWh (9%) and an average monthly demand reduction of 350 kW (10%).

Detailed analyses also indicate the cost-effectiveness of using compressor waste heat recovery systems to provide hot water for brewery cleaning operations (heat energy is recovered by desuperheating the compressor ammonia refrigerant streams). These analyses indicate that savings of $79,000 a year could be realized by using compressor waste heat recovery systems in the brewery. However, the cost of system implementation was found to be in excess of $86,000. Further, the analyses indicate that the benefits of simultaneously implementing waste heat recovery and optimized compressor control are not additive. The use of the control strategies would reduce the energy available for waste heat recovery by approximately 32%, which would reduce the cost savings to approximately $54,200 a year. Nevertheless, although this combined application results in a significant reduction in the savings that can be attributed to the waste heat recovery system, it is important to note that the use of waste heat recovery is still cost-effective. The application would have a payback period of less than two years (based on annual cost savings of $54,000 and implementation costs of $86,400), which is considered to be very good for most industrial and commercial applications.

Although the specific costs and savings of the compressor energy conservation and load management techniques investigated in this project will vary widely for other facilities and process applications, the general conclusion is that proper implementation of the measures will produce significant savings in most food-processing facilities. A follow-up project is under way to assess the use of these control strategies and waste heat recovery techniques in other industrial and commercial applications.

For the utility industry, the widespread use of these compressor energy conservation and load management techniques could result in significant reductions in peak demand loads, which would represent an opportunity for reducing the cost of service. In addition to demonstrating the economic benefits that could be achieved through these measures, this project has served to demonstrate the effectiveness of a joint utility-industry effort. *Project Manager: I. Leslie Harry*

FIRST-GENERATION FUEL CELLS

The major objectives of EPRI's fuel cell research program are to expedite the commercial introduction of first-generation phosphoric acid fuel cells capable of achieving heat rates near 8000 Btu/kWh and using petroleum and coal-derived fuels in an environmentally acceptable manner for dispersed power plant applications; to develop the fuel cell components required to improve power plant heat rates to less than 7500 Btu/kWh; and to develop fuel cell systems for use with coal gasifiers. This report focuses on technical activities directed toward first-generation fuel cell commercialization. Program and project background has been presented in previous EPRI Journal *articles (November 1978, p. 6; June 1980, p. 62).*

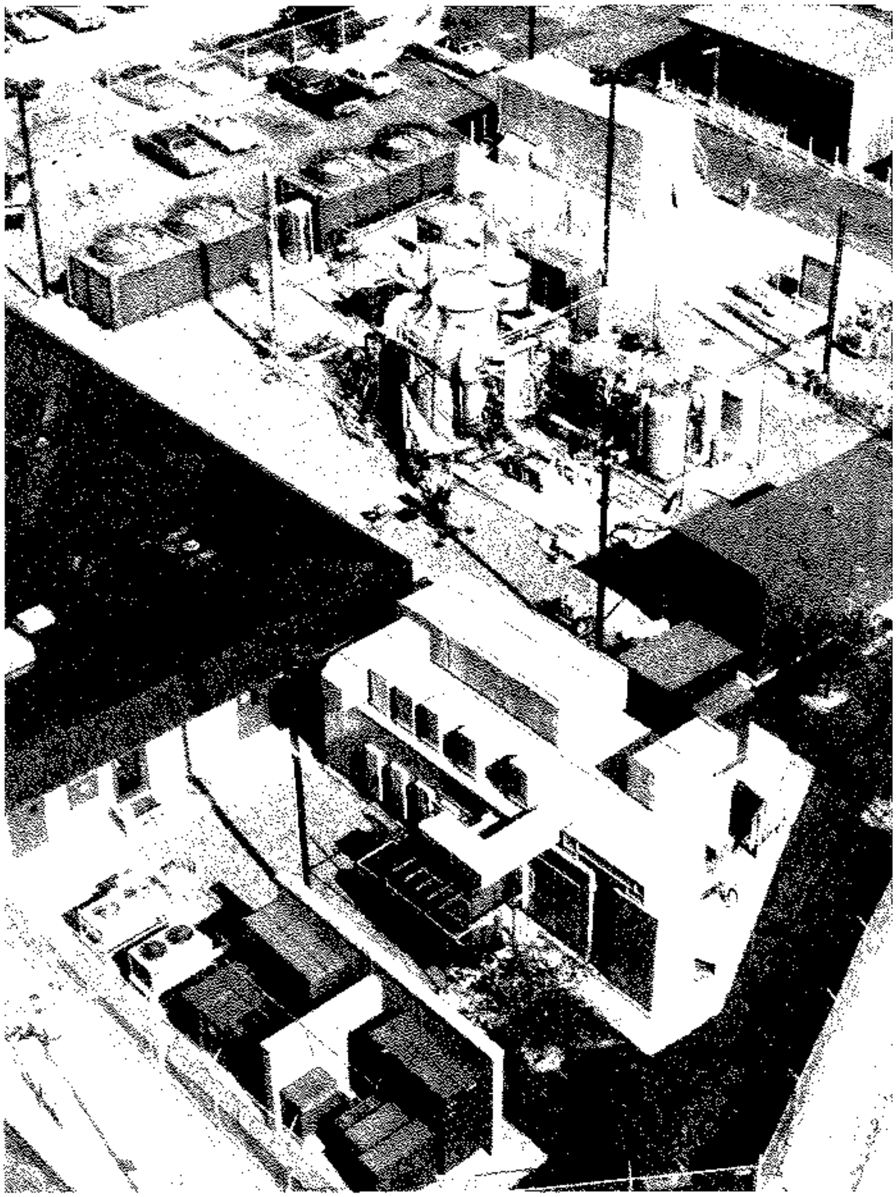
EPRI is supporting the following three major efforts to expedite the commercialization of first-generation phosphoric acid fuel cells.

- Installation and operation of a 4.5-MW net ac (4.8-MW dc) fuel cell module on the system of Consolidated Edison Co. of New York, Inc. (RP842). This is a user-oriented effort to demonstrate that fuel cells can be sited, installed, operated, and maintained by utility personnel and that dispersed fuel cells offer benefits to utility systems.
- Upgrading of the 4.5-MW United Technologies Corp. (UTC) demonstrator to a commercially viable configuration. This is primarily a technical effort aimed at reducing the plant's capital cost and improving its reliability, maintainability, and durability (RP1777). Certain improved components developed in this effort will be retrofitted to the Consolidated Edison plant for verification in a systems context.
- Establishment of the Fuel Cell Users Group to serve as a contact point between utility users and manufacturers, to help stimulate competition among manufacturers, and to provide a bridge between R&D activities and commercial service.

The 4.5-MW demonstration project at Consolidated Edison (Figure 1) has suffered a number of setbacks during the past year, and plant startup has been delayed by approximately one year. Delivery of the reformer pallet was delayed about four months (until December 1980) as a result of a dispute with the fabricator. Before system checkout was completed, several heat exchangers burst because of the freezing of water trapped in their cores after hydrostatic tests of the piping systems. These hydrostatic tests were an unanticipated requirement imposed by the New York City Fire Department. Three heat exchangers have since been replaced. All others, along with virtually all the piping systems, have been pneumatically tested to demonstrate system integrity at nominally two times maximum operating pressure for 24 hours, in accordance with Fire Department requests.

All Fire Department requirements have now been met, and operational checkout of the power plant's fuel-processing, air supply, ancillary, and control systems is under way. If the checkout proceeds on schedule, plant acceptance testing should begin early this year. (A second 4.5-MW power plant, purchased from UTC by Tokyo Electric Power

Figure 1 System checkout is under way at the 4.5-MW (ac) fuel cell installation in midtown Manhattan. Full-power operation is expected to begin this spring.



Co., is on virtually the same schedule; EPRI has no involvement in that project.)

Much progress has been made in the past year to upgrade the 4.5-MW UTC demonstrator to a commercially viable configuration (called Fuel Cell Generator-1, or FCG-1). EPRI has sponsored work to develop a simpler system design and to verify the performance of certain key components in the upgraded design. Related efforts have involved stack technology improvement and scale-up (sponsored by DOE), assessment of system design changes to enable the use of clean coal–derived fuels (Tennessee Valley Authority), and verification of the use of commercial turbocompressor equipment (Niagara Mohawk Power Corp.). These coordinated efforts have led to the power plant specification summarized in Table 1.

The improvements in the commercial plant configuration, however, go well beyond those highlighted in the table. For example, stack life is now predicted to be increased to between 7 and 13 years. Laboratory data from subscale cells also indicate that because new electrocatalysts are performing better than expected, heat rate (after five years of operation) will likely be below 8000 Btu/kWh, even in the earliest prototypes delivered. System simplification studies have reduced the total number of plant components by 37%. Major items eliminated include four heat exchangers, the low-flow turbocompressor, and one startup burner. Two contact coolers now replace the three largest (and most expensive) heat exchangers in the system. All remaining heat exchangers are commercially available shell-and-tube units. The turbocompressors and contact coolers used in the current design are also commercially available. The estimated cost reductions associated with the improved stack technology, system simplifications, and extensive use of commercial components represent a 47% savings over the FCG-1 design that existed one year ago.

Certain performance characteristics have been modified because of the changes in the system. Transient response has been slowed (from seconds to minutes in the worst case), part-power turndown is more limited, and the land required for siting has been increased. The resultant characteristics are still acceptable for dispersed intermediate-duty generation capacity, however, and the system cost savings and improved reliability more than offset the reduction in performance characteristics.

In the past 18 months, the Fuel Cell Users Group has grown from 37 to 55 utility members and has added several nonutility associate members. The group is functioning well, and EPRI support for the administrative staff will end this year, to be assumed by membership assessments. Subcommittees of the users group have had substantial impact on the development of the preferred commercial FCG-1 power plant configuration and performance specification described above. Thus one of the purposes of the group, to transfer technology from R&D managers to users, appears to be succeeding. EPRI will continue to support studies that address specific issues raised by the users group (RP1677). For example, to help individual utilities determine the potential penetration of fuel cells in their system as a function of various performance and cost parameters, Energy Management Associates, Inc., is developing a simplified optimal generation expansion model for use with a simplified cost production model.

Westinghouse Electric Corp. has expressed the intent to develop and market a modular 7.5-MW phosphoric acid fuel cell to compete with the UTC units. EPRI sponsored a study at Westinghouse to assess the effects of alternative fuels on the perfor-

Table 1
FIRST-GENERATION FUEL CELL CHARACTERISTICS

	Demonstrator	Commercial Configuration
Module size (MW)	4.5	11
Heat rate, after 40,000 operating hours (Btu/kWh)		
Full load	9300	8300
Half load	9000	9000
Fuel	Naphtha, natural gas, synthetic natural gas	Light petroleum and coal distillates, natural gas, synthetic natural gas, liquefied petroleum gas, medium-Btu gas, methanol
Projected life (yr)	20*	30†
Projected cost ($/kW)‡	~750	~400
Projected operating and maintenance cost (mills/kWh)	4–5	3–4

*Book life, with cell stack replacement every 40,000 hours.

†Book life, with 10% of stacks replaced each year, beginning after 40,000 hours.

‡In 1979 dollars, not including interest during construction and installation; assumes a production rate of 500 MW/yr.

mance and economics of its air-cooled fuel cell design. Ten plant configurations using five alternative fuels were defined in the study. The results indicate that more closely integrated, and therefore more fuel-efficient, configurations are cost-effective at current and projected fuel prices even though their capital costs are higher. Methanol was found to be the preferred fuel, resulting in a system heat rate of 7800 Btu/kWh at a projected capital cost, in 1980 dollars, of $530/kW. Systems fueled by natural gas and medium-Btu coal gas were also attractive (~8500 Btu/kWh at $580/kW). EPRI support of the Westinghouse effort will continue this year; a detailed power plant design will be initiated that is expected to lead to delivery of two 7.5-MW plants to host utilities in 1986.

The technoeconomics of integrating UTC's FCG-1 phosphoric acid fuel cell with commercially available air-blown fixed-bed gasifiers are being assessed (RP1041). Preliminary results based on lignite indicate that a system heat rate of approximately 10,000 Btu/kWh, with capital cost estimates below $1500/kW (in 1980 dollars), may be achievable in plant sizes of around 50 MW. If the results of this study continue to be promising, a more detailed engineering design and economic assessment will be conducted. *Program Manager: E. A. Gillis*

R&D Status Report
NUCLEAR POWER DIVISION

John J. Taylor, Director

REPAIR WELDING OF HEAVY-SECTION STEEL NOZZLES

EPRI is investigating a partially automated, partially manual repair welding procedure that promises to be able to produce adequate material properties and acceptable levels of residual stress in heavy section steel nozzles in BWRs without postwelding heat treatment (RP1236). The gas-tungsten arc (GTA) automated portion of the procedure, which is a variation of a two-layer GTA refinement welding technique practiced in England, is designed to control the heat-affected zone (HAZ) microstructure. The manual portion of the procedure is used to rapidly complete the deposition of weld metal in the repair cavity.

The discovery of flaws in heavy-section components of LWR primary coolant systems in recent years, together with concern about pressure vessel fracture toughness degradation caused by neutron irradiation, has prompted utilities to consider repair welding procedures that do not require postwelding heat treatment. The ASME Boiler and Pressure Vessel Code (Sections III and XI) permits one such procedure—the half-bead technique—for both preservice and inservice repair.

The half-bead technique derives its name from the partial removal of the first welding pass deposition layer by grinding. The purpose of this removal is to permit heat from the second pass to penetrate and temper any microstructural transformation products present in the remainder of the first layer and its associated HAZ. The technique is an outgrowth of successful attempts in the petrochemical industry to repair pressure vessels in the field by welding without postwelding thermal stress relief. It has also been used in repairing U.S. Navy submarines.

Currently, in the commercial nuclear power industry, preservice flaws that require shallow, localized repair of BWR and PWR cladding are treated by the half-bead technique. The heavy-section steel technology program, sponsored by NRC at Oak Ridge National Laboratory, has demonstrated that repairs made in this way are generally acceptable; that is, the half-bead procedure did not compromise the ultimate strength of the repaired pressure vessel test article. However, this work did not develop detailed material property data for the HAZ and weld metal in the repaired volume; nor was satisfactory information obtained on the distribution and magnitude of residual stresses following repair. Such information is necessary if a fracture mechanics evaluation of the repair weld is to be used to determine service suitability. This evaluation would investigate flaws remaining in the new weldment and the possible initiation and growth of additional flaws in the same volume.

A disadvantage of the half-bead technique is that it is not amenable to automation—a severe penalty for field repairs in the radioactive environment near a nuclear reactor pressure vessel or nozzle. Some rough estimates of the number of welders needed to complete a half-bead field repair have been made on the basis of the time required under favorable shop conditions. It was assumed that a welder under reactor conditions is 75% as efficient as a welder in the shop (in fact, the figure may be significantly lower) and that each welder can remain in the radioactive environment for only about 15 minutes before reaching his quarterly radiation dosage limit. Given these assumptions, a repair that takes 246 man-hours in the shop would require some 1300 welders under reactor conditions. Such estimates indicate the incentive for finding a more rapid, automatic alternative repair method.

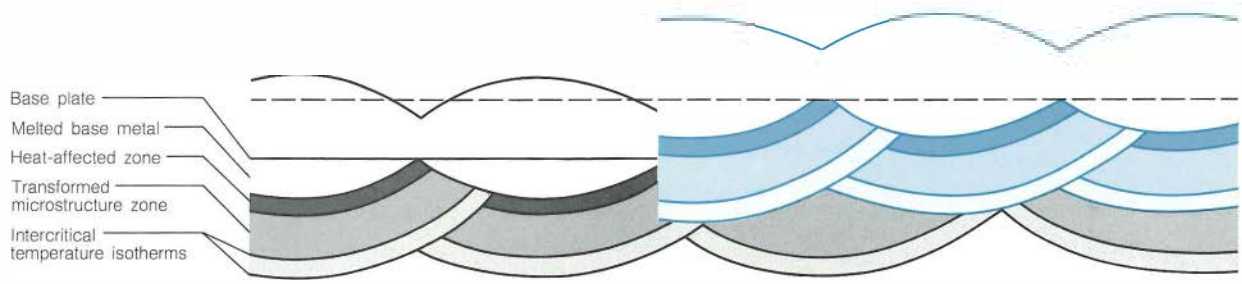
In October 1978 EPRI initiated RP1236 with Babcock & Wilcox Co. to define an alternative repair welding procedure superior to the half-bead technique with respect to ease of implementation and service suitability of the resulting repair. Material property data are being obtained for repair welds made with the half-bead technique and with the selected alternative procedure, and testing will be conducted on heavy-section steel reactor pressure vessel nozzles to compare the service suitability of repair welds made with the two procedures.

Material for the project was purchased from the Japan Steel Works from a melt chemistry within the ASME material specification SA-508 Class 2. Variations within this specification were chosen in order to have above-normal hardenability (i.e., carbon content equivalent) and to be conservatively representative of the majority of SA-508 Class 2 heats in service.

Transverse microhardness measurements were used to screen potential alternative repair procedure candidates. When EPRI solicited unpublished information from around the world on half-bead repairs and their properties, it was found that HAZ hardness ranged from Rockwell C 29 to 36. These values are less than the as-welded hardness but probably higher than the hardness of a weld that has received a typical postwelding heat treatment. The microhardness target set for the alternative repair welding procedure was about Rockwell C 35. A large number of candidates were screened, and those based on manual metal arc processes with interspersed tempering passes or on GTA processes with heat input control proved to be optimal. The manual metal arc tempering passes tended to reduce the peak hardness substantially. The heat input control on the GTA welds was not as impressive but still enabled the microhardness requirements to be met.

The latter approach is a variation of the two-layer grain-size refinement method developed by Marchwood Engineering Laboratories of the Central Electricity Generating Board in England. The CEGB two-layer refinement method was originally developed to control the HAZ grain size in low-alloy steels and provide greater resistance to stress relief cracking during postwelding heat treatment. Because the method does not involve any grinding, it is attractive as an alternative to the half-bead technique.

Figure 1 Two-layer GTA refinement welding. Weld deposits from the first layer are shown on the left, along with the melted base metal, the heat-affected zone, the transformed microstructure zone, and the two intercritical temperature isotherms. (The average first-layer deposit height is indicated by the dashed line.) The second-layer deposits and their associated zones are shown in color on the right.



When the two-layer refinement methodology is applied to manual welding procedures, optimal welding conditions are first identified through an analytic model of (1) empirical correlations that describe the effects of welding variables on weld bead dimensions, (2) classical heat flow (to define the thermal cycle appropriate to the welding conditions and geometry), and (3) basic metallurgy, including phase transformations, grain growth kinetics, and precipitate dissolution kinetics. After the optimal conditions are defined, variations from welder to welder can be examined to guarantee the tolerance of the refinement procedure. The two-layer refinement analytic model has been recalibrated for application to automatic welding of SA-508 Class 2 material.

The GTA process offers a high degree of control over heat input, produces a clean deposit because of the gas shield, does not require slag removal, and lends itself well to automation. When grain size refinement is understood, the heat inputs for the first and second layers can be adjusted so that the second layer will temper the HAZ produced in the base metal (Figure 1). The characteristic ellipsoidal shape of the GTA bead helps control bead overlap and the concomitant HAZ refinement. Results of HAZ hardness measurements indicate a Rockwell C of 35 in the refined case, compared with approximately 45 in the as-welded, unrefined case. Work on optimizing the welding parameters continues, with three- and six-layer variants of the procedure being examined.

Another method of comparing repair welding procedures is to examine the distribution and magnitude of induced residual stresses. When combined with the stresses caused by service loadings, some residual stress states promote crack arrest, others promote crack propagation, and the remainder are relatively neutral. The measurement of residual stresses is, however, both expensive and time-consuming. Surface residual strains, including those at the inside wall of a pressure vessel nozzle, can be estimated from X-ray diffraction measurements of lattice distortion. But attempts to employ off-the-shelf diffraction equipment to measure surface residual strains have demonstrated that the geometric envelope of the nozzle inner base is a serious constraint (Figure 2).

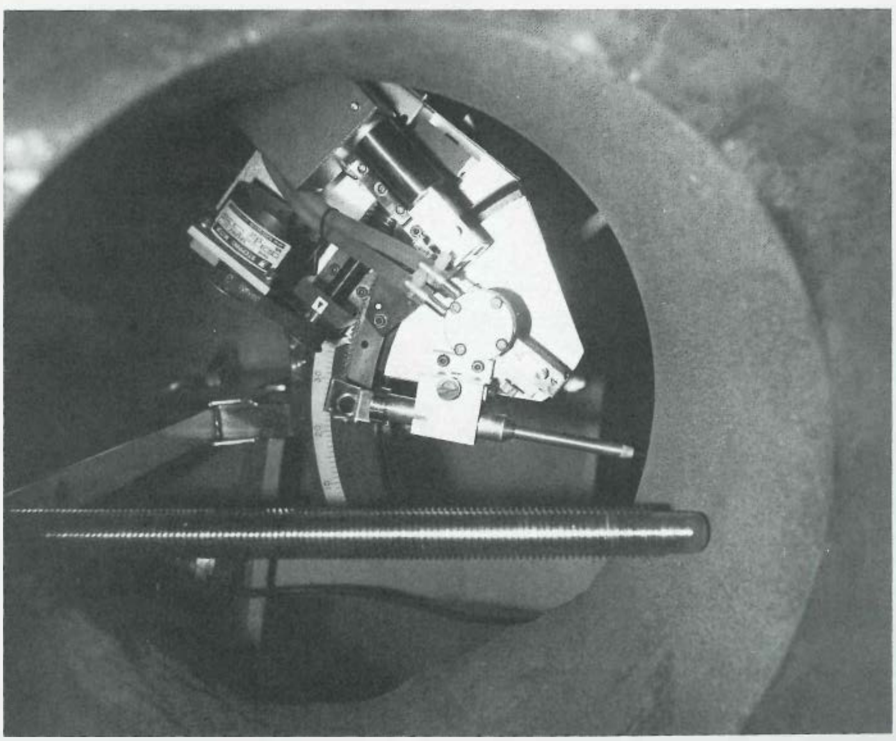


Figure 2 This off-the-shelf X-ray diffraction surface stress analyzer is unable to fit inside the test nozzle bore. The equipment is being modified by Rigaku of Japan to meet this requirement.

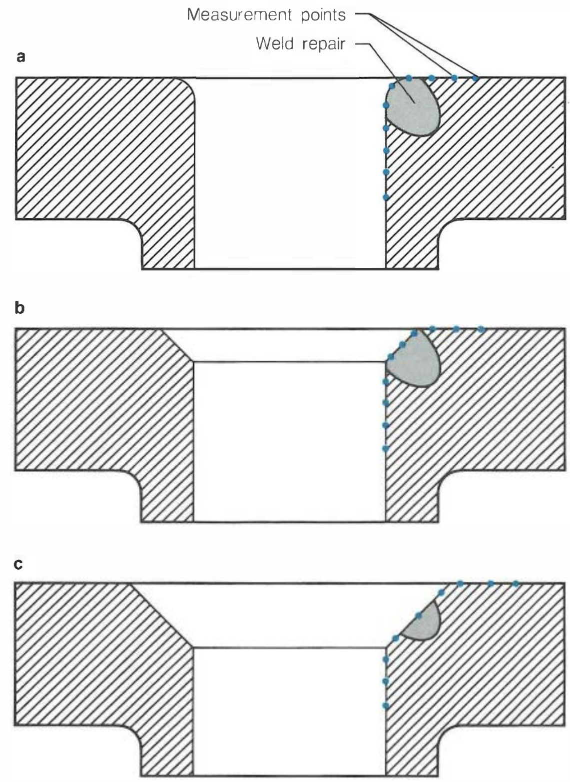
Thus, in connection with RP1236, Babcock & Wilcox has purchased a special portable X-ray diffraction unit from Rigaku of Japan that can be accommodated by the internal diameter of the nozzle test articles. When the equipment has been properly calibrated (early 1982), the location of the highest surface residual stresses in the weld metal, base metal, and HAZ will be determined. Material will then be removed by electropolishing, and the surface measurements will be repeated to assess the effects of final grinding. To determine the distribution of residual stresses away from the surface, X-ray diffraction measurements will be combined with a series of nozzle-blend-radius machining and electropolishing operations (Figure 3). Strain gages adjacent to the machined surface will measure any redistribution of stress that occurs during machining. A finite element computation model will be used to construct the total residual stress field from the sequentially measured values.

Another basis for comparing the half-bead technique and alternative procedures is the resistance of the welds to fatigue crack growth. To date, work has been limited to the properties associated with the half-bead technique. Baseline data on fatigue crack growth in half-bead welds in an air environment at room temperature show that HAZ crack growth rates are slightly, but not significantly, lower than those for the weld metal. Extensive testing remains to be performed.

The final task in the project is to analytically and experimentally compare the service suitability of the repair welds made with the half-bead and alternative welding procedures. Section XI of the ASME Boiler and Pressure Vessel Code provides both flaw analysis and acceptance procedures for use in determining the significance of weld imperfections for pressure vessel safety. The required weld metal and HAZ material property values will be determined by the testing described above, while values for the base metal properties will be taken directly from Section XI, Appendix A. Analytically calculated stresses for identified pressure and temperature transients will be added to the experimentally determined residual stresses. Crack growth and the corresponding stress intensity factor information needed for the Section XI, Appendix A fracture mechanics analysis will be calculated with the aid of the EPRI-developed computer program BIGIF. Calculations will also be made for the case of an unflawed BWR feedwater nozzle to determine the acceptable minimum thickness or area.

In addition to an analytic evaluation of service suitability, a final experimental proof test will be conducted to demonstrate the suitability of the alternative repair weld. A cyclically loaded pressure vessel containing a BWR feedwater nozzle with two repairs, one made by the half-bead procedure and one by the alternative procedure, will be used. This test will thus provide a direct comparison of the fatigue lives of actual nozzle repair welds. *Project Manager: Robert Nickell*

Figure 3 This sequence of nozzle cross sections illustrates the use of X-ray diffraction surface measurements to determine the volumetric residual stress distribution induced by the repair welding procedure. Measurements are first taken at points on the repaired surface and on the nozzle and shell inner surface (**a**). Material is then removed by machining, which causes residual stress redistribution, and new measurements are taken (**b**). The machining operation is repeated and a third set of measurements taken (**c**).



New Contracts

Advanced Power Systems

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP317-03	Liquid Phase Methanol Technology	42 months	300.0	Air Products and Chemicals, Inc. *N. Hertz*
RP832-8	Preliminary Engineering Evaluations of Advanced Liquefaction Concepts	6 months	24.0	Zaininger Engineering Co. *B. Louks*
RP986-9	State-of-the-Art Survey of Wood Gasification Technology	4 months	50.4	Fred C. Hart Associates, Inc. *S. Kohan*
RP1038-6	Application of Dynamic Models of Selective Sulfur Removal Systems	5 months	44.0	Hyprotech, Ltd. *G. Quentin*
RP1092-3	Removal and Relocation of EPRI Air Supply System	3 months	20.3	Boeing Engineering & Construction *J. Bigger*
RP1348-12	Assessments of Advanced Solar Conversion Concepts	6 months	10.0	Nielsen Engineering and Research, Inc. *H. Gilman*
RP1412-11	Test of Methanol as a Utility Boiler Fuel	4 months	50.0	Southern California Edison Co. *H. Schreiber*
RP1509-7	Brayton-Cycle, Solar Central Receiver Commercial Power Plant Systems Study	8 months	33.1	Boeing Engineering & Construction *J. Bigger*
RP1972-1	Assessment of Technical Risks and R&D Requirements for Inertial Confinement Fusion	18 months	486.8	TRW, Inc. *K. Billman*
RP1976-1	Penetration Analysis for Wind Power Systems	10 months	165.4	Science Applications, Inc. *F. Goodman*
RP1989-1	Large Wind Turbine Cost Estimates	9 months	134.5	Bechtel Group, Inc. *S. Kohan*
RP2002-1	Assessment of New Fuel Configurations for Inertial Confinement Fusion	10 months	72.4	University of Illinois at Urbana-Champaign *K. Billman*
RP2048-1	Materials Evaluation for Coal Gasification–Combined-Cycle Plants, Radiation Cooler Materials	27 months	188.6	Lockheed Missiles & Space Co., Inc. *W. Bakker*
RP2049-3	Feasibility Test of EDS Coal Liquid as a Utility Diesel Fuel	9 months	30.5	Easton Utilities Commission *H. Schreiber*
RP2051-1	Sulfur Distribution During Coal Devolatilization and Gasification	1 year	110.0	Westinghouse Electric Corp. *J. McDaniel*

Coal Combustion Systems

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP644-4	Fireside Corrosion Studies at Plant Lansing Smith	7 months	50.0	Southern Research Institute *J. Stringer* *R. Altman*
RP735-3	Condensation in Steam Turbines	2 years	349.9	General Electric Co. *T. McCloskey*
RP781-4	Handbook: Fine Particles	5 months	25.0	Southern Research Institute *R. Carr*
RP982-28	Evaluation of Flue Gas Desulfurization Processes	9 months	77.7	Radian Corp. *D. Stewart*
RP983-12	Static and Dynamic Laboratory Performance of CONAC	4 months	159.3	Science Applications, Inc. *O. Tassicker*
RP1030-20	Surfactant Mechanism Investigation for Dewatering of Fine Coal	21 months	258.9	Dow Corning Corp. *R. Sehgal*
RP1180-13	PFBC Cycle Screening Study	2 months	23.0	Westinghouse Electric Corp. *S. Drenker*
RP1256-5	Assessment of Selective Catalytic Reduction–Baghouse Interaction	5 months	124.4	Southern Research Institute *E. Cichanowicz*
RP1263-8	Poultice Cleanup of PCB Spills	6 months	25.0	Franklin Research Center *R. Komai*
RP1336-2	Construction of a Pressurized Fluidized-Bed Combustion Rig Capable of Operating at Pressures Up to 20 atm	18 months	150.0	National Coal Board *S. Drenker* *J. Stringer*
RP1343-2	Advanced Rotor Forging Procurement	7 months	19.0	Engineering Materials & Processes, Inc. *R. Jaffee*
RP1400-7	Railroad Siding for Coal-Cleaning Test Facility	5 months	370.0	GAL Construction, Inc. *F. Karlson* *D. Trerice*
RP1402-7	Planning Study of Hot-Side Precipitator Problems	11 months	30.0	Affiliated Energy & Environmental Technology *R. Altman*
RP1610-1	Economic Evaluation of Advanced Flue Gas Desulfurization Systems	17 months	245.0	Stearns-Roger Engineering Corp. *T. Morasky*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1648-5	Large Unbalance Analysis of Steam Turbine Generators	11 months	46.9	Maurice L. Adams, Jr. *T. McCloskey*
RP1652-2	Cyclic Reheat Materials Evaluation	2 years	429.8	Stearns-Roger Engineering Corp. *R. Rhudy*
RP1689-10	Advanced Design, High-Reliability Condenser Study	11 months	55.0	Stone & Webster Engineering Corp. *I. Diaz-Tous*
RP1711-1	Root Cause Analysis of Recurring Tube Failures at the Boston Generating Station	15 months	258.9	Boston Edison Co. *J. Parkes*
RP1839-3	Operations Guide for Use of Combustion Additives in Utility Boilers	1 year	84.9	Enerchem Incorporated *J. Dimmer*
RP1856-1	Survey of Steam Turbine Blade Failures	6 months	80.0	Stress Technology, Inc. *J. Parkes*
RP1856-2	Steam Turbine Blade Stress Analysis	18 months	287.2	Stress Technology, Inc. *J. Parkes*
RP1864-2	Vibration Signature Analysis for Predictive Maintenance at United Illuminating Company	29 months	467.2	Radian Corp. *A. Armor*
RP1864-90	Vibration Signature Analysis for Predictive Maintenance at United Illuminating Company	26 months	467.2	The Hartford Steam Boiler Inspection and Insurance Co. *A. Armor*
RP1865-1	Boiler Nondestructive Inspection System	11 months	53.7	Aptech Engineering Services *A. Armor*
RP1871-4	Corrosion Field Testing Support Effort at R. D. Morrow	7 months	72.2	Burns & McDonnell Engineering Co. *C. Dene*
RP1872-2	Maintenance Survey of Flue Gas Desulfurization Systems	6 months	47.4	Battelle, Columbus Laboratories *T. Morasky*
RP1878-3	Demonstration of an Alternative ASME Steam Turbine Generator Acceptance Test	18 months	131.0	General Electric Co. *T. McCloskey*
RP1879-1	Technical and Economic Assessment of Turbine Bypass Systems	1 year	205.4	Power Dynamics, Inc. *T. McCloskey*
RP1890-1	Operations Guide: Boiler Tube Failures	11 months	177.0	Southwest Research Institute *J. Dimmer*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1958-1	Handbook: Water Technology for Thermal Power Systems	27 months	150.0	American Society of Mechanical Engineers *K. Lehner*

Electrical Systems

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1493-2	Behavior of Drilled Shaft Foundations During Undrained Uplift Loadings	17 months	97.8	Cornell University *P. Landers*
RP1507-1	High-Voltage DC Circuit Breaker Experiment	8 months	219.9	Westinghouse Electric Corp. *S. Porter*
RP1518-2	Development of Improved Plow for Installing Underground Distribution Cable: Scorpion Modification	2 months	19.3	Kinnan and Associates *T. Kendrew*
RP1535-3	Radio Broadcast System for Distribution Automation	28 months	1313.2	Altran Electronics, Inc. *B. Blair*
RP1536-7	Study of Electrification Problem Resulting From Liquid Dielectric Flow	1 year	78.0	Massachusetts Institute of Technology *V. Tahiliani*
RP2017-1	Measurement of Electrical Interference on Electric Power Lines	23 months	936.0	SRI International *B. Blair*
RP2115-1	Evaluation of New Concepts to Assess Gas-Insulated Substation Reliability	10 months	50.1	Mashikian and Associates *V. Tahiliani*
RP7893-1	Accessories for Specially Bonded Extruded Dielectric Transmission Cable Systems	25 months	632.6	McGraw Edison Co. *F. Garcia*

Energy Analysis and Environment

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1215-3	Effects on the Electric Utilities of Gas Shortages in Industry	2 months	10.1	Charles A. Berg Associates *S. Braithwait*
RP1219-8	DOE–EPRI Coal Transportation Modeling Conference	4 months	11.0	Argonne National Laboratory *E. Altouney*
RP1225-2	Controlled Studies of Human Health Effects of Short-Term Inhalation of Atmospheric Pollutants	4 years	1982.0	Rancho Los Amigos Hospital, Inc. *J. McCarroll*
RP1587-2	Residential Conservation Strategy Evaluation Model	19 months	50.0	Union Carbide Corp. *S. Braithwait*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1630-19	Western Regional Air Quality Studies: Quality Assurance Services	31 months	309.3	Environmental Research & Technology, Inc. *P. Mueller*
RP1729-1	Aquatic-Sampling Design	38 months	483.3	University of Washington *R. Brocksen*
RP1916-3	Demand 82: National Energy Forecasting Model	2 months	35.0	Applied Forecasting & Analysis, Inc. *L. Williams*
RP1983-1	Impact of Coal Unit Trains on Operation and Maintenance Costs	10 months	100.0	Arthur D. Little, Inc. *E. Altouney*
RP1985-1	Load Forecasting for Small Electric Systems	16 months	149.4	Burns & McDonnell Engineering Co. *J. Wharton*
RP2027-3	Feasibility Study for Risk Assessment Methodology Improvement	3 months	29.1	Stanford University *R. Wyzga*
RP2045-2	Market Saturation for End-Use Technology Decisions	7 months	76.9	Resource Planning Associates, Inc. *E. Beardsworth*
RP2156-1	Acid Rain Issue Decision Framework for Evaluating Alternative Control Measures	6 months	150.0	Decision Focus, Inc. *R. Richels*

Energy Management and Utilization

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1086-11	Electrification in the United States Chemical Industry	3 months	48.3	SRI International *B. Mehta*
RP1136-10	Assist TVA With Electric Vehicle Test and Demonstration Project	4 months	11.8	O. M. Bevilacqua & Associates *J. Mader*
RP1201-22	Utility Impact Potential From Commercial Building Passive Solar Utilization	7 months	53.7	Energy Resources Co. *G. Purcell*
RP1201-23	Heat Pumps in Distillation Process	10 months	50.0	Radian Corp. *J. Brushwood*
RP1275-8	Feasibility Study of Electrostatic Separation of Pyrometallurgical Particulates	1 year	52.4	Lehigh University *I. Harry*
RP1275-9	Industrial Applications of Plasma Processing and of Electron Beams	4 months	35.0	Westinghouse Electric Corp. *I. Harry*
RP1276-5	Evaluation of Design and Analysis of District Heating Systems	18 months	346.2	Burns and Roe, Inc. *S. Hu*
RP1276-10	Preliminary Evaluation of Cogeneration Potential in Distillation Columns	2 months	20.0	Merix Corp. *S. Hu*
RP1791-6	Experimental/Laboratory Studies on Air Saturation and Release for Water-Compensated Compressed-Air Energy Storage Plants	1 year	98.5	University at Buffalo Foundation, Inc. *R. Schainker*
RP1791-8	Compressed-Air Energy Storage Plant Fuel Flexibility and Improvement	18 months	200.0	Brown Boveri Corp. *R. Schainker*
RP1966-1	Adjustable-Speed Drives for Pumps	11 months	170.0	Westinghouse Electric Corp. *J. Brushwood*
RP1967-3	Material Processing Lasers and Their Effects on Energy Use and Productivity	11 months	149.8	IIT Research Institute *J. Brushwood*
RP2033-4	Feasibility Study of Variable-Speed Drives for Heat Pumps	11 months	54.9	University of Minnesota *J. Calm*
RP2033-5	Heat Pump Water Heaters	7 months	56.4	Science Applications, Inc. *J. Calm*

Nuclear Power

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP694-4	Evaluation of Capabilities of Treat Upgrade for Degraded Core Experiments	3 months	12.3	Arne P. Olson Corp. *R. Duffey*
RP695-5	Comparative Analysis of Standard Problems Program	3 months	15.0	Jaycor *G. Srikantiah*
RP711-2	Transverse Electromagnetic Examination Services on Irradiated Fuel Cladding	3 months	30.6	General Electric Co. *D. Franklin*
RP822-8	Minac Advanced Radiography System	8 months	62.1	Schonberg Radiation, Inc. *M. Lapides*
RP891-10	Disturbance Analysis and Surveillance System (DASS) Design Group, Phase 3	6 months	35.0	Combustion Engineering, Inc. *A. Long*
RP891-17	DASS Design Group, Phase 3	4 months	20.0	General Physics Corp. *A. Long*
RP891-19	DASS Design Group, Phase 2	5 months	30.8	Nuclear Software Services, Inc. *A. Long*
RP893-2	Fire Protection Cover Plates and Technology Transfer	4 months	48.6	Factory Mutual Research Corp. *R. Swanson*

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1163-5	Development of Analytic Modules for Nuclear System Analysis	11 months	49.1	Rensselaer Polytechnic Institute *J. Sursock*
RP1237-4	Asymptotic Analysis of Cracked Shell Structure	6 months	25.0	Nutech *D. Norris*
RP1252-7	New Input Module and Improved Restart File Management for EPRI–CPM	6 months	23.6	Pennsylvania Power & Light Co. *W. Eich*
RP1324-5	Experimental Studies of Pipe Whip and Impact	15 months	650.0	Commissariat à l'Energie Atomique *H. Tang*
RP1398-9	Metallurgical Evaluation of Keyway Cracking in Low-Pressure Turbine Disks	6 months	32.8	Southwest Research Institute *M. Kolar*
RP1618-3	Mechanism of Intergranular Corrosion of Inconel 600 Tubing in PWR Steam Generators	23 months	160.3	Research Foundation, Ohio State University *D. Cubicciotti*
RP1628-3	Lifetime of PWR Control Materials, Phase 1	29 months	135.0	The S. M. Stoller Corp. *H. Ocken*
RP1628-5	Control Blade Standards	3 months	26.8	Science Applications, Inc. *H. Ocken*
RP1704-22	Destructive Examination and Evaluation of a Superheater From EBR-2	3 months	50.0	Argonne National Laboratory *K. Winkleblack*
RP1803-3	Initial Study of Annular Array Technology With Associated Ray Tracing for Turbine Disk Inspection	7 months	65.7	Southwest Research Institute *S. Liu* *G. Dau*
RP1846-1	Verification of RELAP 5, MOD 1, for Safety and Relief Valve Discharge Piping Hydraulic Analysis	5 months	41.0	Intermountain Technologies, Inc. *A. Wheeler*
RP1846-2	Dynamic Valve Modeling and Validation Against Data	4 months	50.0	Continuum Dynamics, Inc. *A. Singh*
RP1846-3	Subscale Steam-Water Safety and Relief Valve Testing	3 months	82.5	Acurex Corp. *A. Singh*
RP1846-4	Validation of Sola-Net Safety and Relief Valve Discharge Piping Analysis	4 months	89.8	Flow Science, Inc. *A. Wheeler*
RP1927-2	Evaluation of Critical Flow for Supercritical Steam/Water	13 months	148.2	United Kingdom Atomic Energy Authority *L. Agee*
RP1932-11	Hydrogen Combustion and Management Experiments	25 months	150.0	U.S. Department of Energy *L. Thompson*
RP1932-90	Cosponsor Agreement: Hydrogen Combustion and Management Study	2 months	317.5	Tennessee Valley Authority American Electric Power Services Corp. Duke Power Co. *L. Thompson*
RP1933-4	Feasibility of Studying Volatile Fission Products Released From Irradiated LWR Fuel Under Simulated Accident Conditions	3 months	85.0	Argonne National Laboratory *R. Vogel*
RP2006-2	Data Base for Environmental Crack Model Development	23 months	265.1	Battelle, Columbus Laboratories *J. Gilman*
RP2006-7	Role of Crack-Tip Deformation in Environmentally Assisted Cracking	27 months	241.4	Southwest Research Institute *J. Gilman*
RP2055-4	Metallurgical Analysis of Structural Steels	7 months	14.3	Engineering Materials & Processes, Inc. *T. Marston*
RP2055-5	Significance of Lamellar Tears in Structural Steel	1 year	78.8	Aptech Engineering Services *T. Marston*
RP2058-5	Off-Normal Water Chemistry Survey	6 months	49.9	Aptech Engineering Services *M. Fox*
RP2060-2	High-Purity Steels for Utility Components	33 months	120.8	Bethlehem Steel Corp. *A. Roberts* *R. Jaffee*
RP2060-3	High-Purity Steels for Utility Components	2 years	72.2	University of Leeds *A. Roberts* *R. Jaffee*
RP2079-2	Assistance and Support During the 1981 High-Temperature Gas-Cooled Reactor Design Selection	4 months	16.7	The S. M. Stoller Corp. *M. Lapides*
RP2130-1	Radwaste Solidification and Disposal Criteria	4 months	37.4	Analytic Sciences Corp. *M. Naughton*

Research and Development Staff

Number	Title	Duration	Funding ($000)	Contractor/ EPRI Project Manager
RP1883-2	Coal Pulverizer Materials Development: Effect of Coal Characteristics on Wear, Performance, and Reliability	27 months	588.3	Combustion Engineering, Inc. *W. Bakker*

New Technical Reports

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

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

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ADVANCED POWER SYSTEMS

Advanced-Cooling Full-Scale Engine Demonstration Program

AP-1933 Final Report (RP1319-2); $18.50

This report describes the development and demonstration of an advanced-cooling technology for vanes, blades, and associated hot section components of a combustion turbine. An evaluation of the application of skin-spar-type construction to turbine blading components is presented, along with conceptual designs, deposition test results, and future development plans. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: Arthur Cohn*

Combustion Turbine Combined-Cycle R&D Project Priority Analysis

AP-1943 Final Report (RP990-4); $18.50

The development of a computerized methodology for determining the priority of combustion turbine R&D projects is summarized. The methodology features a combined-cycle plant simulation model and a prioritization algorithm that ranks alternatives on the basis of their benefits and cost-effectiveness. A user's manual, a descriptive case study, and methodology applications are included. The contractors are Encotech, Inc., and Systems Control, Inc. *EPRI Project Managers: A. C. Dolbec and Robert Schainker*

Design of Refractories for Resistance to High-Temperature Erosion-Corrosion

AP-1955 Final Report (RP625-2); $14.00

This report describes a study of dilute-phase erosion of refractories in a pneumatic transport tube. Conditions examined included gas flow velocities, high and low temperatures, three refractories, and three types of transported solids. A mathematical model that describes the rate of particle collisions with the tube wall was developed, and the rate was measured in the pneumatic transport line. The contractor is Westinghouse Research and Development Center. *EPRI Project Manager: John Stringer*

Coal to Methanol: Texaco Gasification and ICI Methanol Synthesis

AP-1962 Final Report (RP832-4); $12.50

This report presents the results of a technical and economic evaluation of producing methanol from bituminous coal by using the Texaco coal gasification process and the Imperial Chemical Industries methanol synthesis process. The processes are described, and the configuration for a large plant, including all supporting, utility, and off-site facilities, is presented. Capital costs, operating costs, and an overall economic evaluation are included. The contractor is Fluor Engineers and Constructors, Inc. *EPRI Project Manager: Nandor Hertz*

Evaluation of Shale Oil as a Utility Gas Turbine Fuel

AP-1975 Final Report (RP1691-2); $12.50

The performance of a gas turbine operating on a hydrotreated Paraho shale oil residual is compared with that of a turbine operating on No. 2 petroleum distillate oil. Exhaust emission data and necessary modifications of the test engine are discussed. The contractor is United Technologies Corp. *EPRI Project Manager: Henry Schreiber*

On-Line Microwave Monitor for Solid Concentration in Coal-Water Slurries

AP-1977 Final Report (RP1654-2); $8.00

The use of microwave techniques to measure coal concentration and linear flow velocity of coal-water slurries was investigated. The dielectric properties of various coal-water slurries were studied, a circulating-slurry test loop with appropriate microwave transmission and detection instrumentation was constructed, and coal concentration and flow rate tests were conducted. The contractor is Science Center Div., Rockwell International Corp. *EPRI Project Manager: T. P. O'Shea*

Fundamental Combustion Studies of Burning Oil-Spray Flames

AP-1978 Final Report (RP1187-3); $11.00

This report discusses burning processes in oil-spray flames and provides technical data for the design of low-NO_x combustors for gas turbines. A bench-scale flame study was conducted, as well as studies on full-size gas turbine combustors operated at atmospheric pressure and full-size test-stand combustors operated at higher pressures. A laser velocimeter was used to measure hot gas velocities. The contractor is General Electric Co. *EPRI Project Manager: R. L. Duncan*

COAL COMBUSTION SYSTEMS

Air-Gas System Dynamics of Fossil Fuel Power Plants: System Excitation Sources

CS-1444 Interim Report, Vol. 5 (RP1651); $17.00

An ongoing project is investigating aerodynamic disturbances in the air-gas system of fossil fuel power plants. This volume describes work to characterize disturbances generated by centrifugal fans. A laboratory facility was built and instrumented to gather data on fan disturbances, and analytic expressions developed from these data have been incorporated into an air-gas system computer model. The contractors are Westinghouse Electric Corp. and the Massachusetts Institute of Technology. *EPRI Project Manager: I. A. Diaz-Tous*

Cofiring of Refuse-Derived Fuel and Coal: Boiler Corrosion Evaluation

CS-1983 Final Report, Vol. 1 (RP898-1); $20.00

A 4000-h controlled-temperature probe evaluation was conducted at Wisconsin Electric Power Co.'s Oak Creek Unit 7 to determine the long-term impact of cofiring coal and refuse-derived fuel on the corrosion of boiler materials. Results of probe exposure to the daily firing cycle in the water-wall, superheater, and cold-pass sections of the boiler are presented. Specific evaluations included weight loss, penetration, metallurgical evaluation, and deposit–base metal interfaces. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: C. R. McGowin*

Evaluation of Potential Processes for Recovery of Metals From Coal Ash

CS-1992 Final Report (RP1404-2); Vol. 1, $8.00; Vol. 2, $18.50

Volume 1 summarizes the methods, results, and conclusions of a two-year study that evaluated several processes for removing aluminum and trace metals from coal fly ash. The two most promising processes, direct hydrochloric acid leaching and pressure digestion acid leaching, are described, and the data required for further process improvement are discussed. Volume 2 contains the data and calculations used to derive process flow sheets for removing the metals and separating them into salable products. It includes detailed flow sheets, material balances, heat balances, and cost estimates. The contractor is Oak Ridge National Laboratory. *EPRI Project Manager: D. M. Golden*

Particulate Emission Characteristics of Oil-Fired Utility Boilers

CS-1995 Final Report (RP1131-1); $11.00

This report presents the results of a test program to develop basic information on the quantity, composition, and formation of oil particulate matter emitted from representative oil-fired utility sources. Details are given on the three test boilers, test conditions and methods, boiler operational data, the analytic techniques used, and fuel analyses and other supporting data. The contractors are KVB, Inc., and Consolidated Edison Co. of New York, Inc. *EPRI Project Manager: M. W. McElroy*

Coal Waste Artificial Reef Program, Phase 3

CS-2009 Interim Report (RP1341-1); Vol. 1, $9.50; Vol. 2, $32.00; Vol. 3, $8.00

This report describes advanced waste disposal evaluation to explore the feasibility of ocean disposal of large-volume coal combustion wastes. Volume 1 summarizes the Phase 3 results. It describes the fabrication of blocks from coal wastes, laboratory investigations, and the construction of a demonstration reef from 15,000 stabilized waste blocks. The environmental acceptability of the blocks and their suitability for reef construction are addressed. Volume 2 reports the Phase 3 results in detail. Volume 3 presents an engineering-economic assessment of coal waste block production and ocean disposal. Capital cost and operation and maintenance cost estimates (in 1980 dollars) were developed for the entire ocean disposal system for a hypothetical eastern seaboard power plant. The contractors are Marine Sciences Research Center and Michael Baker Jr., Inc. *EPRI Project Manager: D. M. Golden*

Fines Recycle Modeling for an Atmospheric Fluidized-Bed Coal Combustor

CS-2010 Final Report (RP1179-6); $9.50

A fine-carbon combustion model was modified to predict coal combustion efficiencies as a function of several process variables in the Babcock & Wilcox 6-by-6-ft atmospheric fluidized-bed coal combustion facility. Coal fines combustion kinetics were determined by using the model and fines recycle test data from the facility. By combining the combustion model and empirically determined coal fines kinetics, the overall combustion efficiency in the facility was determined as a function of fines recycle rate, superficial gas velocity, bed depth, freeboard length, and fines reentry temperature. The contractor is General Atomic Co. *EPRI Project Manager: C. J. Aulisio*

Variable-Thickness Transient Groundwater Flow Model: User's Manual

CS-2011 Final Report (RP1406-1); $12.50

This report describes the variable-thickness transient groundwater flow model, which uses finite difference techniques to simulate two-dimensional saturated groundwater flow. The model was developed to enable utilities to predict the flow of leachate in an aquifer. This manual presents basic information on the model as well as specific data requirements. It describes the physical parameters, boundary conditions, and initial conditions that must be specified. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: D. M. Golden*

Advanced Rotor-Bearing Systems for Feedwater Pumps, Phase 2

CS-2027 Final Report (RP1266-7-1); $9.50

This report summarizes the second phase of an ongoing effort to develop design improvements to reduce feed pump vibration problems. In this phase two promising areas were investigated: squeeze-film dampers for feed pump applications and interstage sealing configurations to provide additional vibration damping at midspan locations between the journal bearings. Guidelines and methodologies important to the implementation of these design improvements are discussed. The contractors are Maurice L. Adams, Jr., and Elemer Makay. *EPRI Project Manager: J. P. Dimmer*

Root Causes of Plant Outages Attributed to Boiler Controls

CS-2028 Final Report (RP1265-5); $8.00

This report discusses boiler control system problems, common failure modes, associated root causes, and suggested corrective actions. The data base on boiler control problems was reviewed and expanded in order to identify and rank common symptoms and abnormal events. The boiler startup sequence was found to be the operating mode with the most problems. Extreme service requirements, a hostile environment, and personnel-induced damage were identified as probable causes of system failures. The contractor is Jaycor. *EPRI Project Manager: J. P. Dimmer*

Coal Ash Disposal Manual: Second Edition

CS-2049 Final Report (RP1685-3); $30.50

This updated manual presents a systematic, objective methodology for evaluating coal ash disposal sites and methods in light of cost considerations and current government regulations. Intended to serve as an aid in the selection and operation of ash disposal systems, the manual provides specific disposal criteria and outlines methodologies for decision making and cost estimating. It also covers the physical and chemical properties of ash, current disposal philosophies, conceptual disposal system designs, case studies, and site reclamation. The contractor is GAI Consultants, Inc. *EPRI Project Manager: D. M. Golden*

Solvent Recovery for the Oil Agglomeration Coal-Cleaning Process

CS-2057 Final Report (RP1840-1); $9.50

Laboratory testing was conducted to study solvent removal and recovery from coal pellets produced by the spherical agglomeration coal-cleaning process. Three dryers were selected for testing. This report describes the laboratory thermal drying setup, compares the performance of the dryers, and outlines a proposed pilot plant study. The contractor is Ontario Hydro. *EPRI Project Manager: Randhir Sehgal*

Coal- and Ash-Handling Systems Reliability Conference and Workshop Proceedings

WS-79-236 Proceedings; $44.00

This report presents papers, discussion summaries, and conclusions from an EPRI workshop on reliability problems with coal- and ash-handling systems in power plants. Held in October 1980 in St. Louis, the workshop covered yard and in-plant coal handling, frozen coal, fugitive dust, fly ash handling, bottom ash handling, and ash disposal. The contractor is Stone & Webster Engineering Corp. *EPRI Project Manager: I. A. Diaz-Tous*

ELECTRICAL SYSTEMS

Human Factors Review of Electric Power Dispatch Control Centers

EL-1960 Interim Report (RP1354-1); Vol. 1, $9.50; Vol. 2, $29.00

A human factors survey of 13 utility control centers was conducted. The survey evaluated the information available to operators, the physical interface between the operators and the power systems, and the operational setting. Particular emphasis was placed on the design of the cathode-ray tube interface, the data base, facility lighting, training, manning, and work stress. Areas for further study were identified. Volume 1 summarizes the survey results, and Volume 2 presents them in detail. The contractor is Stagg Systems, Inc. *EPRI Project Managers: D. F. Koenig and C. J. Frank*

Distribution System Reliability and Risk Analysis Models

EL-2018 Final Report (RP1356-1); Vol. 1, $6.50; Vol. 2, $15.50; Vol. 3, $14.00

This report documents a project to develop distribution system reliability and risk analysis models for the electric utility industry. Volume 1 is an executive summary of the project. Volume 2 presents the theoretical and utility background material used in developing the models. Included are the results of a survey of current utility reliability evaluation practices and needs. Volume 3 describes the models developed: a historical reliability assessment model and a predictive reliability assessment model. It discusses the models' designs, input requirements, capabilities, and limitations. It also describes program validation work and utility testing of the models. The contractor is Westinghouse Electric Corp. *EPRI Project Managers: W. E. Shula and R. A. Lambeth*

Effects of Reduced Voltage on the Operation and Efficiency of Electric Loads

EL-2036 Final Report (RP1419-1); Vol. 1, $18.50; Vol. 2, $18.50

To quantify the energy consumption of electric load components as a function of supply voltage, a wide variety of loads were tested at seven input voltages. Volume 1 describes the test specifications, procedures, and results. Volume 2 presents appendixes of recorded and calculated data. The contractor is the University of Texas at Arlington. *EPRI Project Manager: H. J. Songster*

Distribution System Simulator Design

EL-2052 Final Report (RP1526-1); $23.00

The feasibility of a digital-computer-based distribution system simulator for use in studying non-power frequency phenomena was explored, and a development plan outlined. Specifications for the simulator are based on input collected at five workshops attended by 40 distribution engineers. Computing requirements to satisfy the specifications were investigated, and the cost and man-hour requirements of developing the simulator were estimated. The contractor is McGraw-Edison Co. *EPRI Project Managers: R. A. Lambeth and H. J. Songster*

New Technologies for Overhead Transmission Line Inspections

EL-2056 Final Report (RP1497-2); $9.50

A preliminary assessment of the feasibility of applying modern technologies to overhead transmission line inspection was conducted. The project identified the data needed from transmission line inspections, symptoms of problem conditions, techniques for detecting problem conditions, and environmental factors that influence sensing techniques. It also addressed the cost-effectiveness of inspection methods. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: John Dunlap*

ENERGY ANALYSIS AND ENVIRONMENT

Regional Load Curve Models: QUERI Model

EA-1672 Final Report (RP1008); Vol. 2, $12.50; Vol. 4, $14.00

A model was developed to relate hourly electricity demand in a given region to both rapidly changing variables, such as weather, and slowly changing variables, such as population, appliance stock, and industrial mix. Volume 2 describes the specification, estimation, and validation of the model. Volume 4 presents the regional hourly demand forecasts generated by the model and describes the sensitivity analyses performed. The contractor is Quantitative Economic Research, Inc. *EPRI Project Managers: Ahmad Faruqui and A. G. Lawrence*

Aircraft Data Summaries for the SURE Intensives

EA-1910 Final Report (RP862); 6 vols. (priced per vol.)

As part of the Sulfate Regional Experiment (SURE), six intensive air quality sampling programs using instrumented aircraft were conducted in the eastern United States. The primary objective of these programs was to measure the vertical profiles of gases, particulates, and air temperature and humidity. These volumes present the aerometric and meteorological data collected. The contractors are Meteorology Research, Inc., and Research Triangle Institute. *EPRI Project Manager: G. R. Hilst*

Statistical Summaries for the SURE Aircraft Measurements

EA-1911 Final Report (RP862); $17.00

This report presents the results of statistical analyses of the aerometric data collected by aircraft during the Sulfate Regional Experiment (SURE). The contractor is Meteorology Research, Inc. *EPRI Project Manager: G. R. Hilst*

Reference Manual of Data Sources for Load Forecasting

EA-2008 Final Report (RP1478-1); $33.50

A project was undertaken to examine the availability and quality of data on variables that are frequently used in load forecasting. The data requirements of three load-forecasting models were determined, and utility and government sources of data on over 100 variables were surveyed. Alternative data sources were also evaluated, and recommendations were made for data development. The contractor is Mathematical Sciences Northwest, Inc. *EPRI Project Manager: Ahmad Faruqui*

Greenhouse Soil Heating for Improved Production and Energy Conservation

EA-2022 Final Report (RP1110-1); $11.00

A three-year study of the use of simulated power plant reject heat for soil heating in greenhouses is described. Data were collected on soil temperature and moisture distribution, heat transfer rates, and lettuce production yields under various operating conditions. The contractor is the Ohio Agricultural Research and Development Center. *EPRI Project Manager: R. K. Kawaratani*

Environmental Impacts of Energy Transportation

EA-2039 Final Report (TPS76-661); $18.50

This report reviews available information on the environmental impacts of fuel transportation for the electric utility industry. The transportation of coal is emphasized, but oil, natural gas, liquefied natural gas, methanol, and hydrogen are also covered. Research gaps and significant requirements for further study are identified. The contractor is Mathtec, Inc. *EPRI Project Manager: R. E. Wyzga*

Transuranium and Other Radionuclides in the Environs of Nuclear Power Plants

EA-2045 Final Report (RP1059); $15.50

Work was conducted to establish the concentrations and distribution of certain radioactive elements, particularly transuranics, in the environment around nuclear power plants and to determine what amounts can be attributed to plant operation and what to fallout from weapons testing. Soil, vegetation, and air samples were taken at four nuclear power plants and 10 sites remote from nuclear plants and examined for several radioactive species, especially plutonium. The results are summarized, and the program design and sampling methods outlined. The contractor is Battelle, Pacific Northwest Laboratories. *EPRI Project Manager: R. M. Perhac*

Control of Nitrogen Oxides: Assessment of Needs and Options

EA-2048 Final Report (RP1375); 6 vols. (priced per vol.)

This six-volume report, a technical support document for EA-2050, presents information needed by utilities to deal with several pending NO_x-related regulatory changes. Volume 1 is an introduction and summary. Volume 2 covers the legislative and regulatory environment; Volume 3, atmospheric physical phenomena relevant to NO_x concentration; Volume 4, the major classes of mathematical models that might be used in assessing NO_x-related air quality and visibility impacts; Volume 5 (forthcoming), emission control technology for combustion sources; and Volume 6, the selection and application of air quality models. The contractor is Systems Applications, Inc. *EPRI Project Manager: R. E. Wyzga*

NO_x Regulatory Changes and the Electric Utility

EA-2050 Final Report (RP1375); $14.50

This report—a guidance manual for air quality modeling in planning, siting, and emissions control—is designed to provide a comprehensive summary of the information needed to deal with several pending NO_x-related regulatory changes. It reviews current regulatory requirements, the implications of the pending changes, and NO_x control technology costs and capabilities. Procedures are presented for designing a modeling strategy, conducting a site screening analysis, and selecting appropriate models. The contractors are Systems Applications, Inc., and KVB, Inc. *EPRI Project Manager: R. E. Wyzga*

Assessment Methodology for New Cooling Lakes: Limnological and Fisheries Data and Bibliography

EA-2059 Final Report (RP1488-1); $24.50

This volume presents the limnological and fisheries data used in developing a methodology to assess multiple-use benefits from cooling lakes. Data compiled from the open literature, computerized data files, and utilities are provided for 181 lakes and reservoirs. A bibliography of data sources is also included. The contractor is Tetra Tech, Inc. *EPRI Project Manager: I. P. Murarka*

New Modes of Heating, Ventilation, and Air Conditioning

EA-2060 Proceedings (RP1050); $20.00

This report contains the papers presented at a workshop sponsored by EPRI in January 1979 in Tampa, Florida, to survey and critique state-of-the-art developments in heating, ventilation, and air conditioning technology. The papers address such issues as engineering feasibility, cost-effectiveness, the state of market readiness, and questions on rate design, ownership, and tax and other policy incentives. The contractor is the University of Arizona. *EPRI Project Manager: Edward Beardsworth*

Conference Proceedings: Environmental Risk Assessment

EA-2064 Proceedings (RP1316-6); $20.00

EPRI sponsored a conference in New Orleans in December 1980 on environmental risk assessment and the effects of new regulations on the utility industry. This report presents papers and discussion group transcripts from the conference. Topics include specific regulations and their use of risk assessment, consolidated permits, a legal perspective on the role of risk assessment in setting standards, control costs, the use of epidemiological data, and the state of the art of risk assessment for toxic substances. The contractor is Sigma Research, Inc. *EPRI Project Manager: R. E. Wyzga*

ENERGY MANAGEMENT AND UTILIZATION

Off-Peak Power Use in Passive Solar Homes

EM-1966 Interim Report (RP1191-7); $8.00

This report describes the thermal performance of two passive solar homes and an identical standard home used as a control. The peak electricity demand rates of these homes are compared, and off-peak refrigeration of homes with large quantities of thermal mass is discussed. A computer model that is being developed to assess the potential of off-peak refrigeration is also described. The contractor is the University of Arizona. *EPRI Project Manager: T. M. Lechner*

Preliminary Engineering Design and Cost of ACAS Plant

EM-1998 Final Report (RP1699-1); $21.50

Design and cost data are presented for the A-5 hybrid advanced compressed-air storage plant. Also described are the design, plant heat and mass balance, and major systems of the conventional baseline compressed-air energy storage plant. The performance and cost estimates of the baseline and advanced plants are compared. The contractors are United Engineers & Constructors, Inc., and Brown Boveri Corp. *EPRI Project Manager: R. B. Schainker*

AC/DC Power Converter for Batteries and Fuel Cells

EM-2031 Final Report (RP841-1); $18.50

This report presents the results of a program to design an advanced power converter for use in battery energy storage and fuel cell generation systems in the 1980s. It describes the design analysis for each major subsystem and component; various ways of optimizing a 14-MW wide-range converter; and the requirements for some of the converter components. An assessment of the basic program is included, and a number of future program needs are identified. The contractor is United Technologies Corp. *EPRI Project Manager: R. J. Ferraro*

Technologies for Energy Conservation in AC Motor-Driven Systems

EM-2037 Final Report (RP1201-13); $15.50

This report evaluates and compares techniques for energy conservation by reducing losses in ac motor-driven systems: the NASA power factor controller, Wanlass motor modification, conventional variable-frequency solid-state inverters, and other variable-frequency drives and schemes. Impacts on electric utility systems in terms of harmonics, power factor of operation, and electromagnetic interference are considered. The contractor is the University of Minnesota. *EPRI Project Manager: R. J. Ferraro*

Residential Cool Storage Implementation Handbook

EM-2054 Final Report (RP1089-1); $9.50

A field instrumentation program and an analytic studies program were conducted to provide quantitative data for use by utilities in evaluating and developing customer-side cool storage as a means of electric load management. The results are presented, and the operating characteristics of commercially available cool storage components and systems are described. A detailed computer simulation of cool storage systems is included. The contractor is Carrier Corp. *EPRI Project Manager: J. S. Brushwood*

NUCLEAR POWER

PWR FLECHT SEASET Unblocked-Bundle Forced and Gravity Reflood Data

NP-1459 Interim Report (RP959-1); Vol. 1, $27.50; Vol. 2, $59.00

This report is a systematic compilation of data from the unblocked 161-rod bundle forced and gravity reflooding tests conducted under the FLECHT SEASET program. Volume 1 presents detailed descriptions of the experimental system, the instrumentation, the test procedures, and the data reduction methods. Volume 2 (Appendix C) contains the data obtained in 63 valid tests performed with the 17 × 17-rod bundle having a cosine axial power profile. The data represent sample tables and plots for each run. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: K. H. Sun*

BWR Refill-Reflood Program 30°-Sector Experimental Plan

NP-1525 Interim Report, Vol. 1 (RP1377-1); $18.50

This volume presents the experimental task plan for the CCFL/refill system effects tests (30° sector) of the BWR Refill-Reflood Program. It discusses task objectives, required modifications to existing 30°-sector test facility, test parameters and ranges, individual test categories, measurement plan approach, and data utilization. The contractor is General Electric Co. *EPRI Project Manager: Mati Merilo*

Standard for Requalification of Nuclear Pressure-Boundary Components

NP-1921 Final Report (RP1756-1); $15.50

This report provides a rationale for developing a new industry code or standard to cover all foreseeable future situations of component requalification. System considerations, component considerations, and specific methods of component evaluation are detailed, with emphasis on the need for requalification as the result of an abnormal operating event. Existing documentation that may be useful in requalification is discussed, and specific proposals for a standard are presented. The contractor is Teledyne Engineering Services. *EPRI Project Manager: S. W. Tagart, Jr.*

Nondestructive Methods for Residual Stress Measurement

NP-1971 Final Report (RP1395-5); $11.00

This report reviews and evaluates the technology currently available for the nondestructive measurement of residual stress. The principles of various techniques—hole drilling and ring coring, ray diffraction, ultrasonic techniques, and electromagnetics—are described, as well as their limitations and application parameters. Directions for future research are indicated. The contractor is the Pennsylvania State University. *EPRI Project Manager: J. R. Quinn*

Mechanical Property Degradation of Steels Exposed to PLBR Liquid Sodium

NP-1985 Final Report (RP1704-15); $8.00

This report describes a literature survey conducted to investigate the feasibility of using ferritic steels instead of austenitic steels for certain components of a prototype large breeder reactor (PLBR). Analyses of carburization, decarburization, and the effects of sodium exposure on the mechanical properties of ferritic and austenitic steels are presented. Areas for future research are recommended. The contractor is SRI International. *EPRI Project Manager: R. L. Jones*

Analysis of Potential Attack on Insulating Materials Exposed to Sodium

NP-1986 Final Report (RP1704-16); $9.50

A project was undertaken to discover commercially available insulating ceramics suitable for the header of an LMFBR. A series of thermodynamic calculations was used to determine ceramics that are compatible with liquid sodium at prototype large breeder reactor temperatures. A test program was then conducted in which the selected ceramics were exposed to liquid sodium at 741 K for 10 weeks. On the basis of these limited results, the study indicates that pure MgO and Al_2O_3 do not react with sodium. The contractor is SRI International. *EPRI Project Manager: J. T. A. Roberts*

Friction Measurements of Steel on Refractory Bricks

NP-1987 Final Report (RP1704-17); $6.50

Experiments were conducted to determine the necessary friction coefficients to allow the calculation of stresses generated at the interface between the reactor vessel bottom and the refractory brick support base in a prototype large breeder reactor design concept. Static and dynamic friction coefficients were measured between various refractory materials and 2¼Cr-1Mo steel; the effects of sliding velocity, contact pressure, type of refractory brick, lubricants, temperature, and surface conditions were determined; and various methods of constructing a flat support base with a relatively smooth surface were considered. The contractor is SRI International. *EPRI Project Manager: R. L. Jones*

Cyclic Load and Environmental Effects on Stress Corrosion Cracking of Sensitized Stainless Steel

NP-1991 Final Report (RP311-3); $8.00

This report documents a laboratory study on the effects of oxygen concentration, temperature, and cyclic loading on the intergranular stress corrosion cracking of sensitized type-304 stainless steel in BWRs. Test conditions are described and the results evaluated. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: M. J. Fox*

Browns Ferry Unit 3 Cavity Neutron Spectral Analysis

NP-1997 Final Report (RP772-3); $9.50

Neutron dosimetry measurements were performed in the Browns Ferry Unit 3 reactor cavity by using multiple dosimeter and spectrum unfolding techniques to assess radiation-induced degradation. Test results indicate the feasibility of determining neutron flux spectra and densities in the pressure vessel cavity region by dosimetric measurements. The contractor is General Electric Co. *EPRI Project Manager: H. A. Till*

Post-DNB Operation for LWRs

NP-1999 Final Report (RP1382-1); Vol. 1, $17.00; Vol. 2, $14.00

The feasibility of a post-DNB (departure of nucleate boiling) fuel design limit for LWRs was studied. Experimental data were reviewed to determine the impact of post-DNB operation on various phenomena, the various benefits of a post-DNB fuel design limit were quantified, and an R&D program was defined. The contractors are Combustion Engineering, Inc. (Vol. 1), and Babcock & Wilcox Co. (Vol. 2). *EPRI Project Manager: P. G. Bailey*

Tornado Missile Simulation and Design

NP-2005 Final Report (RP616-2); Vol. 1, $15.50; Vol. 2, $30.50

This report describes the development of a probabilistic methodology to predict the potential risks of tornado-propelled missiles to nuclear power plant structures. Volume 1 presents the simulation methodology, case study analysis, missile velocity data, and TORMIS computer simulation code documentation. Volume 2 contains the mathematical models and updated data base for the tornado characteristics, missile aerodynamics and trajectory, and structure damage assessment. The contractor is Research Triangle Institute. *EPRI Project Manager: B. B. Chu*

Single-Phase Natural Circulation Experiments on Small-Break Accident Heat Removal

NP-2006 Interim Report (RP1731-1); $9.50

This report describes single-phase natural circulation heat removal experiments conducted in a natural circulation facility composed of four loops, each containing a U-tube heat exchanger. Results are provided for 30 experimental conditions, including one to four active loops, three input powers, three secondary cooling rates, forced to natural circulation, and the addition of noncondensable gas. Results from laser-Doppler velocimeter tests in an active and inactive hot leg are also included. The contractor is SRI International. *EPRI Project Managers: K. H. Sun, J. R. Sursock, and Yoram Zvirin*

Two-Phase Natural Circulation Experiments on Small-Break Accident Heat Removal
NP-2007 Interim Report (RP1731-1); $9.50

This report summarizes experimental results obtained in a natural circulation test facility—a U-tube steam generator two-loop model. It describes the test facility and its instrumentation and data acquisition systems, shakedown tests, and test procedures. Details of the individual tests are presented, along with representative results in the form of computer-generated plots and reproductions of strip-chart records. The contractor is SRI International. *EPRI Project Manager: J. P. Sursock*

Static Stress-Intensity Factors and Dynamic Crack Propagation in Pipes
NP-2024 Annual Report (RP231-1); $17.00

This report summarizes recent efforts in a study of crack initiation, propagation, and arrest and associated fluid depressurization behavior in pressurized piping components. Predictive models for critical flaw sizes, the initiation and propagation of dynamic cracks in pipes, and dynamic crack propagation in compact specimens are described, as well as fundamental properties governing rapid crack propagation and arrest. Use of the three-dimensional finite element code SAP IV and the thermal-hydraulic code LEAKER is discussed. The contractor is the University of Washington. *EPRI Project Manager: John Carey*

Feedwater Nozzle Inspection Evaluation
NP-2025-SY Summary Report (RP1448); $11.00

This report summarizes a series of investigations into ultrasonic testing (UT) of reactor pressure vessel feedwater nozzles for detection of thermal fatigue cracks. It includes an assessment of the reliability of contemporary field UT techniques and describes the development and use of a mock-up nozzle available to utilities for verification of proposed techniques. The relationship between inspection capability and fitness-for-service determinations is also discussed. The contractor is Southwest Research Institute. *EPRI Project Manager: M. E. Lapides*

Finite Element Model for Eddy-Current NDT Phenomena
NP-2026 Interim Report (RP1395-2); $11.00

A study was conducted to determine the feasibility of applying finite element numerical techniques to the modeling of eddy-current nondestructive testing (NDT) phenomena. This report describes the development and verification of a finite element eddy-current computer code that predicts actual test data with high precision. The code is limited to steam generator tube geometries and axially symmetric flaws. The contractor is Colorado State University. *EPRI Project Manager: J. R. Quinn*

Operability Review of Prototype Large Breeder Reactor Designs
NP-2030 Final Report (RP1704-2); $14.00

In this operability review of prototype large breeder reactor designs, 14 normal and off-normal events were analyzed, including startup, shutdown, refueling, reactor scram, and loss of feedwater. The procedures and findings are presented, along with approximately 100 recommendations for improving the operability of these future plants. The contractor is General Physics Corp. *EPRI Project Manager: R. K. Winkleblack*

THERMIT: Computer Program for Three-Dimensional Thermal-Hydraulic Analysis of LWR Cores
NP-2032 Final Report (RP518); $14.00

This report describes THERMIT, a three-dimensional thermal-hydraulic code for the analysis of LWR cores. It includes a discussion of models and methods, a guide to user application, programming information, and sample calculations. The contractor is the Massachusetts Institute of Technology. *EPRI Project Manager: G. S. Lellouche*

Survey and Analysis of Communications Problems in Nuclear Power Plants
NP-2035 Final Report (RP501-5); $11.00

A survey of four operating nuclear power plants, covering a range of reactor types and operating conditions and experience, was conducted to investigate communications problems. This report describes the study methodology (including procedures for sampling verbal communications in a control room), presents the results, discusses the general power plant communications environment and the problems identified, and makes recommendations for R&D that could lead to improvements. The contractor is General Physics Corp. *EPRI Project Manager: H. L. Parris*

Steam Generator Sludge Pile Model Boiler Testing: Sludge Characterization
NP-2041 Topical Report (RPS119-1); $12.50

This report describes chemical and physical analyses of eight plant sludges and several simulated sludges. These analyses were part of a study of sludge buildup in PWR steam generator tubesheet regions. X-ray diffraction measurement and emission and X-ray fluorescence spectroscopy were used. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: D. A. Steininger*

Radiographic System for Evaluation of Steam Generator Support Plate Integrity
NP-2042 Final Report (RPS105-1); $9.50

This report describes the development of a radiographic technique to determine the integrity of steam generator support plate ligaments between flow holes and tube holes. The technique proved to be sensitive to simulated tube support cracks and also capable of discriminating between ligament cracks and incomplete ligaments where drilled flow holes and tube holes intersected. The hardware for manipulating and controlling the radiographic source and the film cassettes was also developed. The contractor is Combustion Engineering, Inc. *EPRI Project Manager: G. W. DeYoung*

Single-Tube Thermal and Hydraulic Tube Support Test
NP-2046 Final Report (RPS118-1); Vol. 1, $9.50; Vol. 2, $23.00

This report describes an experimental project to determine the inception and extent of dryout or liquid-deficient heat transfer and chemical precipitation in presently used steam generator tube–tube support geometries and modified geometries. Volume 1 summarizes the results of thermal and hydraulic tests with pure water; chemistry tests; and thermal, hydraulic, and chemical precipitation testing with modified quatrefoil configurations. Volume 2 contains appendixes that present the data in detail. The contractor is Westinghouse Electric Corp. *EPRI Project Manager: D. A. Steininger*

Non-U.S. Advanced Low-Level Radwaste Treatment Systems
NP-2055 Interim Report (RP1557-1); $11.00

An overview of advanced low-level radwaste treatment systems in use or under development outside the United States is presented. Power plant radwaste treatment practices in Canada, Japan, Korea, and Europe are covered. Information was obtained by visits to plants and research centers and a survey of the applicable literature. The report also reviews the status of work on radwaste volume-reduction systems and radwaste incinerators in the United States. The contractor is Sargent & Lundy Engineers. *EPRI Project Manager: M. D. Naughton*

Analysis of Selected Critical Experiments Using ENDF/B-IV and ENDF/B-V Data
NP-2076 Final Report (RP978-1); 6.50

This report describes work to determine the impact of the recently released ENDF/B-V nuclear data files on earlier analyses of benchmark experiments for thorium-fueled PWRs and spectral shift reactors. ENDF/B-V data were used to analyze selected critical experiments, and the results were compared with parameters and values obtained when ENDF/B-IV data were used. A heterogeneous cell calculation in 85 energy groups was performed for each configuration. The contractor is Combustion Engineering, Inc. *EPRI Project Managers: Odelli Ozer and B. R. Sehgal*

R&D STAFF

Techniques for the Preparation of High-Temperature Alloys Capable of Forming Protective Silica Scales
PE-2034 Final Report (TPS79-731); $6.50

The feasibility of using melting and casting techniques and powder metallurgical techniques to produce iron- and nickel-based alloys containing SiC particles was investigated. The results indicate that it is technically feasible to introduce nickel-coated SiC particles into the melt, but that the melt must be quickly cast to preserve the dispersoids. Powder metallurgical techniques seem preferable. Low-chromium alloys with excellent oxidation resistance have been produced. The contractor is Battelle, Columbus Laboratories. *EPRI Project Manager: John Stringer*

Workshop Proceedings: Rotor Forgings for Turbines and Generators
WS-79-235 Proceedings; $60.50

An EPRI-sponsored workshop on rotor forgings for steam turbines and electric generators was held in Palo Alto, California, in September 1980. The papers and discussion summaries presented in this volume cover the historical development of rotor technology and the present status of the field. Eight critical issues that form the basis of much ongoing R&D are discussed in detail. Task force recommendations for future R&D on four classes of rotors (very large, cycling, combination, and very high temperature) are included. *EPRI Project Manager: R. I. Jaffee*

Patents

Each issue of the *Journal* includes a list of newly filed patent applications. The EPRI identification number, title, and abstract filed with the application are reprinted below. Information on obtaining a license under EPRI patent or patent application can be obtained from the Manager, Patents and Licensing, P.O. Box 10412, Palo Alto, California 94303; (415) 855-2866.

Information on other licensable inventions, as well as computer codes available from EPRI, is published quarterly in the *EPRI Guide*. This publication can be obtained from Research Reports Center, P.O. Box 50490, Palo Alto, California 94303; (415) 965-4081.

Thermionic fault current limiter and method of current limiting
ED0281-81-02

A thermionic fault current limiter utilizes either a vacuum or plasma environment for a plurality of spaced conduction electrodes. The electrode can be supported by insulative spacers, with the electrode providing shadow shields for the supporting spacers. Electrode spacing, power density, temperature gradients, and control grids can be utilized for optimal operation and in establishing self-absorption of energy for a desired operating environment. Cesium desorption from the electrode surfaces can be utilized to enhance current termination (TPS 80-731).

Method for enhancing the sulfur capture potential of lime by using a filter in the flue gas
ED0719-80-12

A method is provided for improving the sulfur capture potential of lime in the fluidized-bed combustion of coal and for improving the flow characteristics of the feed coal therefor. It comprises collecting partially sulfated limestone particles from the fly ash of the flue gas from the fluidized-bed combustor and (a) retaining said particles in the flue gas stream, thereby hydrating said particles, and returning said particles to the combustor; or (b) mixing said partially sulfated limestone particles with wet coal, thereby drying said coal and simultaneously hydrating unreacted calcium oxide to form calcium hydroxide, and recycling said mixture of dry crushed coal and calcium hydroxide into said fluidized-bed combustor; or (c) introducing wet coal in the flue gas upstream from said collected particles, thereby providing moisture to hydrate said particles, and returning said hydrated particles to the combustor.

Method for dissolving magnetite at low temperature
EDS125-81-14

A method is provided for removing magnetite corrosion from ferrous metal at a temperature of about 50°C to 60°C. It comprises contacting the corrosion with an aqueous solution of a borohydride salt and an organic chelating reagent. The preferred composition is an aqueous solution of 0.15 molar sodium borohydride and 0.04 molar disodium ethylenediaminetetraacetic acid.

Nonlinear voltage-limiting device having specific stability and antiflashover characteristics and method of fabrication
KD0657-01-09

A nonlinear voltage-limiting device displaying a particular stability characteristic and designed to eliminate flashover failure across its circumferential edge is disclosed herein, along with a specific method of fabrication. The voltage-limiting device is characterized by a rising resistive current with time at predetermined temperature and voltage levels and includes a disk-shaped wafer composed primarily of zinc oxide. In accordance with the method disclosed herein, after this wafer is formed and sintered in accordance with prescribed temperature and time requirements, its circumferential edge is provided with an antiflashover coating that requires curing. Thereafter, the coated wafer is annealed in a way that cures the coating and, at the same time, reduces and preferably minimizes the characteristic rise in resistive current referred to above.

Cable-following apparatus that utilizes a releasable cable gripping mechanism
KD1287-01-04

A cable-following apparatus especially suitable for use in replacing existing underground cable by reaming around and along the length of the cable is disclosed herein. This apparatus includes a main body or cable follower that is interconnected with the cable to be replaced for slidable movement along the latter. To accomplish this, the apparatus includes a specifically designed mechanism for releasably gripping the cable at least at one end, preferably two points along the cable, in a specifically controlled fashion. At the same time, the apparatus provides means for reaming around the cable, preferably by one or more floor jets. Once the soil surrounding the cable has been loosened by using this apparatus, the cable can be easily pulled out of the ground. A replacement cable can be attached to the existing cable and therefore pulled into place.

An electrical transformer assembly constructed of magnetic strip material
KD1290-02-21

An electrical transformer assembly comprising a core outer leg, a core center leg centered within the outer leg, and a coil disposed between the center and outer legs. The core outer leg is cylindrical in shape and constructed of layers of narrow-width magnetic strip material. The core center leg has a stacked construction and may also be constructed of narrow-width magnetic strip material. The peripheral boundary of the coil is located adjacent to the inner surface of the core outer leg. End caps are disposed at both ends of the core center and outer legs to support the legs. Leads from the coil pass through at least one of the end caps.

A contoured varistor having constant current density characteristics
KD1421-01-04

A varistor comprising a sintered body composed principally of metal oxide and having opposite end surfaces is disclosed herein, along with a particular technique for maintaining a uniform current density across the varistor body during periods when surge current passes therethrough, whereby to increase the energy absorption capability of the varistor. This is accomplished by contouring the sintered body to be longer along its edges than through its center.

Inspection system
KD1704-04-01

A system for the remote visual inspection of an annulus defined between two vessels. A conduit member is disposed in the annulus, having one end adjacent an upper portion of the vessel and the other end terminating adjacent an area to be inspected. The conduit member is provided with at least one aperture adjacent the area to be inspected and sized to receive a housing that contains a camera and a light source. The housing and light source are introduced into the conduit member by a support means that includes at least a first hollow, flexible hose member having a first end connected to the housing and a second end terminating adjacent an upper portion of the vessel. The flexible hose member is made sufficiently rigid for introducing the housing through the conduit member by pressurization with a fluid. The system further includes a source of electric power for the camera, a light, and display means for receiving signals from the camera, as well as means for maintaining the camera at a desired temperature.

Remote visual inspection system
KD1704-04-03

A system for the remote visual inspection of a structure, including two vessels, one disposed within the other and defining an annulus therebetween. A guide member is provided circumferentially about an upper periphery of the two vessels. Mounted on the guide member are two motor-driven, diametrically opposed trolleys that support a flexible track member which extends downward through the annulus from one of the trolleys and back up the other side of the annulus to the other trolley. At least one motor-driven carriage is mounted on the track member and carries a camera and light source. By appropriate positioning of the trolleys and the carriage, all the surfaces of the vessels defining the annulus are accessible for visual inspection by the camera. In accordance with a particular preferred embodiment, markers are placed at preselected points in the annulus on one of the vessels to permit verification of the location of the camera and carriage. Advantageously, the markers are in the form of a preselected pattern to provide verification of the clarity of the image being transmitted by the camera. In accordance with another preferred embodiment, the system further includes means for recording signals received from the camera and simultaneously recording the position of the camera.

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